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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, DC 20549

FORM 10-K

(Mark One)

? ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended: December 31, 2018

OR

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from to

Commission file number: 001-38040

ALTA MESA RESOURCES, INC.

(Exact name of registrant as specified in its charter)

Delaware	**81-4433840**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
15021 Katy Freeway, Suite 400, Houston, Texas	**77094**
(Address of principal executive offices)	**(Zip Code)**

Exhibit
CP- 0757
Fetkovich

Registrant's telephone number, including area code: 281-530-0991

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Class A Common Stock, par value $0.0001 per share	AMR	The NASDAQ Capital Market
Warrants to purchase one share of Class A Common Stock	AMRWW	The NASDAQ Capital Market

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☐ No ☒

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☐ No ☒

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files.) Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer	☒	Accelerated filer	☐	Non-accelerated filer	☐
Smaller reporting company	☐	Emerging growth company	☐		

Exhibit
Trustee 0120

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ☐ No ☒

The aggregate market value of the voting and non-voting common stock held by non-affiliates of the registrant as of June 28, 2018 (the last business day of the registrant's most recently completed second fiscal quarter) was approximately $776,593,856 based on the closing price of the shares of common stock on that date.

As of June 28, 2019, there were 182,613,382 shares of Class A Common Stock and 199,987,976 shares of Class C Common Stock, par value $0.0001 per share outstanding. The shares of Class A Common Stock shown as outstanding do not include 735,855 unvested restricted stock awards outstanding as of June 28, 2019.

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Glossary of Terms

The definitions and abbreviations set forth below apply to the indicated terms used throughout this filing.

Company Specific Terms -	
2018 Predecessor Period -	The period from January 1, 2018 through February 8, 2018.
2024 Notes -	$500 million outstanding principal amount of senior unsecured notes of Alta Mesa bearing interest at 7.875%, payable semi-annually, maturing in December 2024.
Alta Mesa -	Alta Mesa Holdings, LP. This entity conducts our Upstream activities.
Alta Mesa GP -	Alta Mesa Holdings GP, LLC, a majority owned subsidiary of SRII Opco, LP.
Alta Mesa RBL -	Alta Mesa Eighth Amended and Restated Credit Agreement with Wells Fargo Bank, National Association, as administrative agent. This credit agreement is a reserve based loan or RBL.
Alta Mesa Services -	A wholly owned subsidiary of Alta Mesa Holdings, LP.
AM Contributor -	High Mesa Holdings, LP, a partnership formed in connection with executing the Business Combination.
AMR -	Alta Mesa Resources, Inc.
ARM -	ARM Energy Management, LLC, a company that markets our oil and gas production and provides services relating to our derivatives.
BCE -	BCE-STACK Development LLC, a fund advised by Bayou City Management, LLC.
Business Combination -	The acquisition by Alta Mesa Resources, Inc. of controlling interests in Alta Mesa Holdings GP, LLC, Alta Mesa Holdings, LP, and KFM Midstream, LLC.
HMI -	High Mesa, Inc., the predecessor owner of Alta Mesa Holdings, LP.
KFM -	Kingfisher Midstream, LLC. This entity conducts our Midstream activities.
KFM Contributor -	KFM Holdco, LLC.
KFM Credit Facility -	Kingfisher Midstream, LLC amended and restated senior secured revolving credit facility with Wells Fargo Bank, National Association, as the administrative agent.
Midstream -	Reportable business segment representing our midstream activities.
Predecessor Periods -	The years ended December 31, 2017, 2016, 2015 and 2014 and the 2018 Predecessor Period.
Riverstone Contributor -	Riverstone VI Alta Mesa Holdings, L.P.
Successor Period -	The period from February 9, 2018 through December 31, 2018.
Sponsor -	Silver Run Sponsor II, LLC.
SRII Opco -	SRII Opco, LP is a subsidiary of Alta Mesa Resources, Inc. and direct owner of Alta Mesa Holdings, LP and Kingfisher Midstream, LLC.
Tax Receivable Agreement -	Tax Receivable Agreement dated as of February 9, 2018, among Alta Mesa Resources, Inc., SRII Opco, LP, Riverstone VI Alta Mesa Holdings, L.P., and High Mesa Holdings LP.
Upstream -	Reportable business segment representing our exploration and production activities.
Oil, Gas and Other Terms -	
3D Seismic -	(Three-Dimensional Seismic Data) Geophysical data that depicts the subsurface strata in three dimensions. 3-D seismic data typically provides a more detailed and accurate interpretation of the subsurface strata than two-dimensional seismic data.
Basin -	A large natural depression on the earth’s surface in which sediments generally brought by water accumulate.
bbl -	One stock tank barrel, of 42 U.S. gallons liquid volume, used herein to describe volumes of crude oil, condensate or natural gas liquids.
bbld -	Barrels per day.
Bcf -	One billion cubic feet of natural gas.
Bcfe -	One billion cubic feet of natural gas equivalent with one barrel of oil converted to six thousand cubic feet of natural gas. The ratio of six thousand cubic feet of natural gas to one bbl of oil or natural gas liquids is commonly used in the oil and natural gas business and represents the approximate energy equivalency of six thousand cubic feet of natural gas to one bbl of oil or natural gas liquids.

Boe -	One barrel of oil equivalent is determined using the ratio of six Mcf of natural gas to one barrel of oil, condensate or natural gas liquids. The ratio of six Mcf of natural gas to one bbl of oil or natural gas liquids is commonly used in our business and represents the approximate ratio of energy content between natural gas and oil, and does not represent the price equivalency of natural gas to oil or natural gas liquids.
Boed -	One Boe per day.
Btu -	(British Thermal Unit) The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.
Completion -	The process of treating a drilled well followed by the installation of permanent equipment for the production of natural gas or oil.
Condensate -	A mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.
Cryogenic -	The process of using extreme cold to separate NGLs from the natural gas stream.
DD&A -	Depreciation, depletion and amortization.
Developed acreage -	The number of acres that are allocated or assignable to productive wells or wells capable of production.
Developed reserves -	Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the related equipment is relatively minor compared to the cost of a new well.
Development costs -	Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and natural gas.
Development well -	A well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.
Differential -	An adjustment to the market reference price of oil, natural gas or natural gas liquids from an established spot market price to reflect differences in the quality and/or location of oil or natural gas.
Dry hole -	A well found to be incapable of producing hydrocarbons in commercial quantities.
Dry hole costs -	Costs incurred in drilling an unsuccessful exploratory well, including plugging and abandonment costs.
Dth -	A dekatherm is a unit of energy used primarily to measure natural gas and is equal to 1,000,000 Btu.
EBITDA -	Earnings before interest, taxes, depreciation, depletion and amortization.
EBITDAX -	Earnings before interest, taxes, depreciation, depletion, amortization and exploration expenses.
Enhanced recovery -	The recovery of oil and natural gas through the injection of liquids or gases into the reservoir, supplementing its natural energy. Enhanced recovery methods are often applied when production slows due to depletion of the natural pressure.
Exploitation -	A development or other project which may target proven or unproven reserves (such as probable or possible reserves), but which generally has a lower risk than that associated with exploration projects.
Exploratory well -	A well drilled to find a new field or to find a new reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well or a stratigraphic test well.
Field -	An area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations.
Formation -	A layer of rock which has distinct characteristics that differs from adjacent rock.
Fracing, fracture stimulation technology, hydraulic fracturing -	A well stimulation technique to improve a well's production by pumping a mixture of fluids into the formation to create hydraulic fractures which intersect existing natural fractures. As part of this technique, sand or other material may also be injected to keep the hydraulic fracture open, so that fluids or natural gases may more easily flow through the formation.
Gross acres or gross wells -	The total acres or wells in which a working interest is owned.

Held by production -	Acreage covered by mineral leases that perpetuates a company's right to operate a property usually requiring production to be maintained at a minimum economic quantity of production.
Horizontal drilling -	A drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled at an angle within a specified interval.
Lease operating expenses -	The expenses of lifting oil or natural gas from a producing formation to the surface, constituting part of the current operating expenses of a well. Such expenses include labor, supplies, repairs, utilities, environmental and safety, maintenance, allocated overhead costs, severance taxes, insurance and other expenses incidental to production, but excluding lease acquisition, drilling or completion expenses.
Mbbl -	One thousand barrels of crude oil, condensate, natural gas liquids, or produced water.
Mbbld -	One thousand barrels per day.
MBoe -	One thousand Boe.
MBoed -	One thousand Boe per day.
Mcf -	One thousand cubic feet of natural gas.
Mcfd -	One thousand cubic feet per day.
Mcfe -	One thousand cubic feet equivalent determined using the ratio of one barrel of oil, condensate or natural gas liquids to six Mcf of natural gas.
Mcfed -	Mcfe per day.
MMBoe -	One million boe.
MMBtu -	One million British thermal units.
MMBtud -	One million British thermal units per day.
MMcf -	One million cubic feet of natural gas.
MMcfd -	One million cubic feet per day.
MMBbl -	One million barrels of crude oil, condensate or natural gas liquids.
Net acres -	The total acres a working interest owner has attributable to a particular number of acres, or a specified tract.
Net production -	Portion of production owned by us after production attributable to royalty and other owners.
Net revenue interest -	A working interest owner's working interest in production after deducting royalty, overriding royalty, production payments and net profits interests.
NGLs or natural gas liquids -	Natural gas liquids are a group of hydrocarbons including ethane, propane, normal butane, isobutane and natural gasoline.
NYMEX -	The New York Mercantile Exchange.
P&A -	(Plug and Abandonment) is the permanent dismantlement and removal of production equipment and facilities from service at the end of an asset's economic life.
PDNP -	Proved developed non-producing reserves.
PDP -	Proved developed producing reserves.
Produced water -	Byproduct associated with the production of crude oil and natural gas that often contains a number of dissolved solids and other materials found in oil and gas reservoirs.
Productive well -	A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the production exceed production expenses and taxes.
Proved developed reserves -	Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods and can be expected to be recovered through extraction technology installed and operational at the time of the reserve estimate.
Proved properties -	Properties with proved reserves.
Proved reserves -	Quantities of oil and natural gas, which can be estimated with reasonable certainty to be economically producible from known reservoirs, and under existing economic conditions, operating methods and government regulations.
Proved undeveloped reserves ("PUD") -	Reserves that are expected to be recovered from new wells, or from existing wellbores where a relatively major expenditure is required to make the well producible.

PV-10 -	When used with respect to oil and natural gas reserves, PV-10 means the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development and abandonment costs, using prices and costs in effect at the determination date, before income taxes, and without giving effect to non-property related expenses, discounted to a present value using an annual discount rate of 10%. PV-10 is not a financial measure calculated in accordance with generally accepted accounting principles ("GAAP") and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenue. Neither PV-10 nor Standardized Measure represents an estimate of the fair market value of our oil and natural gas properties. We and others in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific tax characteristics of such entities.
Realized price -	The cash market price less all expected quality, transportation and demand adjustments.
Recompletion -	The process of treating an existing wellbore in an attempt to establish or increase existing production.
Reserves -	Estimated remaining quantities of oil and natural gas anticipated to be economically producible from known accumulations.
Reservoir -	A porous and permeable underground formation containing a natural accumulation of producible oil and/or natural gas that is confined by impermeable rock or water barriers and is separate from other reservoirs.
Resources -	Quantities of oil and natural gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable and another portion may be considered unrecoverable.
Royalty -	An interest in an oil and natural gas lease that gives the owner the right to receive a portion of the production from the leased acreage (or of the proceeds from the sale thereof), but does not require the owner to pay any portion of the production or development costs on the leased acreage.
SEC -	United States Securities and Exchange Commission.
Service well -	A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, produced water disposal, water supply for injection, observation, or injection for in-situ combustion.
Spacing -	The distance between wells producing from the same reservoir. Spacing in horizontal development plays is often expressed in terms of feet, e.g., 1000 foot spacing, and is often established by regulatory agencies.
STACK -	An oilfield in the eastern portion of the Anadarko Basin; STACK is an acronym describing both its location —Sooner Trend Anadarko Basin Canadian and Kingfisher County—and the multiple, stacked productive formations present in the area.
Standardized Measure -	Standardized measure is the present value of estimated future net revenue to be generated from the production of proved reserves, determined in accordance with the rules and regulations of the U.S. Securities and Exchange Commission, without giving effect to non-property related expenses such as certain general and administrative expenses, interest expense and depletion, discounted using an annual discount rate of 10%.
Stratigraphic test well -	A drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production. The classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as "exploratory type" if not drilled in a known area or "development type" if drilled in a known area.
Success rate -	The percentage of wells drilled which produce hydrocarbons in commercial quantities.
Undeveloped acreage -	Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage contains proved reserves.
Unit -	The joining of all or substantially all interests in a reservoir or field, rather than a single tract, to provide for development and operation. Also, the area covered by a unitization agreement.
Unproved properties -	Properties with no proved reserves.
VWAP -	Volume weighted average price.
Waterflood -	The injection of water into an oil reservoir to "sweep" additional oil out of the reservoir rock and into the wellbores of producing wells. Typically, an enhanced recovery process.

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Working interest -	The right granted to the lessee of a property to explore for and to produce and own natural gas or other minerals. The working interest owners bear the exploration, development, and operating costs.
Workover -	Operations on a producing well to restore or increase production.

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Cautionary Statement Regarding Forward-Looking Statements

The information in this Annual Report includes “forward-looking statements” within the meaning of Section 27A of the Securities Act of 1933, as amended (the “Securities Act”), and Section 21E of the Securities Exchange Act of 1934, as amended (the “Exchange Act”). All statements, other than statements of historical fact included in this Annual Report, regarding our strategy, future operations, financial position, estimated revenue and losses, projected costs, prospects, plans and objectives of management are forward-looking statements. When used in this Annual Report, the words “could”, “should”, “will”, “plan”, “believe”, “anticipate”, “intend”, “estimate”, “expect”, “project”, the negative of such terms and other similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. These forward-looking statements are based on our current expectations and assumptions about future events and are based on currently available information as to the outcome and timing of future events. When considering forward-looking statements, you should keep in mind the risk factors and other cautionary statements described under the heading “Risk Factors” included in Part I, Item 1A of this Annual Report. These forward-looking statements are based on management’s current belief, based on currently available information, as to the outcome and timing of future events.

Forward-looking statements may include statements about:

- our ability to continue as a going concern;
- our ability to comply with, or amend the terms of, the covenants and restrictions imposed by our debt agreements, including our ability to repay amounts borrowed under the Alta Mesa RBL that exceed the current borrowing base;
- our business strategy;
- our reserve quantities and the present value of our reserves;
- our exploration and drilling prospects, inventories, projects and programs;
- our drilling, completion and production technology;
- our ability to replace the reserves we produce through drilling and through acquisitions;
- future oil and gas prices;
- the supply and demand for our production and our midstream services;
- the timing and amount of our future production;
- our hedging strategy and expected results;
- competition and government regulation;
- our ability to obtain permits and governmental approvals;
- expected or anticipated changes in the Oklahoma forced pooling system;
- pending legal and environmental matters;
- our future drilling plans, spacing plans and development pace;
- our marketing of our production;
- our leasehold or business acquisitions;
- our costs of developing our properties;
- the sufficiency of our liquidity position to ensure financial flexibility and fund our operations and capital expenditures;
- our access to capital, including constraints from the cost and availability of debt and equity financing;
- our ability to hire, train or retain qualified personnel;
- general economic conditions;
- operating hazards and other risks incidental to transporting, storing, gathering and processing natural gas, natural gas liquids, crude oil and midstream products;
- our future operating results, including production levels, initial production rates and yields in our type curve areas;
- the costs, terms and availability of midstream services;
- our plans, objectives, expectations and intentions contained in this Annual Report that are not historical; and
- our ability to collect receivables from High Mesa, Inc. and its subsidiaries.

We caution you that any forward-looking statements are subject to all of the risks and uncertainties, most of which are difficult to predict and many of which are beyond our control, incident to the exploration for and development, production, gathering and sale of oil, natural gas and natural gas liquids. Some factors that could cause actual results to differ materially from those expressed or implied by these forward looking statements include, but are not limited to, the ability of the combined company to realize the anticipated benefits of the Business Combination, commodity price volatility, global economic conditions, including supply and demand levels for oil, gas and NGLs, inflation, increased operating costs, lack of availability of drilling and production equipment, supplies, services and qualified personnel, liabilities resulting from litigation or the SEC investigation, difficulty in obtaining necessary approvals and permits, uncertainties related to new technologies, geographical concentration of our operations, environmental risks, weather risks, security risks, drilling and other operating risks, regulatory changes, the uncertainty inherent in estimating oil and gas reserves and in projecting future rates of production, reductions in

cash flow, lack of access to capital, our ability to satisfy future cash obligations, restrictions in our debt agreements, the timing of development expenditures, managing our growth and integration of acquisitions, cyber-attacks, failure to realize expected value creation from property acquisitions, title defects, limited control over non-operated properties, and the other risks described under "Item 1A. Risk Factors" in this Annual Report.

Estimating quantities of oil, natural gas and NGL reserves is complex and inexact. The process relies on interpretations of geologic, geophysical, engineering and production data. The extent, quality, reliability and interpretation of these data can vary. The process also requires a number of economic assumptions, such as oil, natural gas and NGL prices, the relative mix of oil, natural gas and NGLs that will be ultimately produced, drilling and operating expenses, capital expenditures, the effect of government regulation, taxes and availability of funds. Future prices received for production and costs may vary, perhaps significantly, from the prices and costs assumed for purposes of these estimates. In addition, the results of drilling, testing and production activities may justify revisions of estimates that were made previously. If significant, such revisions would change the schedule of any further production and development drilling. Accordingly, reserve estimates may differ significantly from the quantities of oil and gas that are ultimately recovered.

Should one or more of the risks or uncertainties described in this Annual Report occur, or should underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements.

Except as otherwise required by applicable law, we disclaim any duty to update any forward-looking statements, all of which are expressly qualified by the statements in this section, to reflect events or circumstances occurring after the date of this Annual Report.

PART I

Item 1. Business

Overview

Alta Mesa Resources, Inc., together with its consolidated subsidiaries ("we" or "the Company"), is an independent exploration and production company focused on the acquisition, development, exploration and exploitation of unconventional onshore oil and natural gas reserves in the eastern portion of the Anadarko Basin in Oklahoma. We operate in two reportable business segments - Upstream and Midstream. Alta Mesa Holdings, LP ("Alta Mesa") conducts our Upstream activities and owns our proved and unproved oil and gas properties located in an area of the Anadarko Basin commonly referred to as the STACK. We generate upstream revenue principally by the production and sale of oil, gas and NGLs. We also operate in the Midstream segment through Kingfisher Midstream, LLC ("KFM"). KFM has a gas and oil gathering network, a cryogenic gas processing plant with offtake capacity, field compression facilities and a produced water disposal system in the Anadarko Basin that generate revenue primarily through long-term, fee-based contracts. The KFM assets are integral to our Upstream operations, which we conduct in the same region, and they are strategically positioned to provide similar services to other producers in the area. Our principal offices are at 15021 Katy Freeway, Suite 400, Houston, Texas 77094 and our main phone number is (281) 530-0991.

We were originally incorporated in Delaware in November 2016 as a special purpose acquisition company under the name Silver Run Acquisition Corporation II for the purpose of effecting a merger, capital stock exchange, asset acquisition, stock purchase, reorganization or similar business combination involving the Company and one or more businesses.

In connection with the closing of the Business Combination discussed below, the Company changed its name from "Silver Run Acquisition Corporation II" to "Alta Mesa Resources, Inc."

Beginning in the 1990's, our predecessor operations were focused on vertical wells, waterfloods and analyzing the commercial productivity of the stacked formations on our acreage. Since 2012, our activities have become primarily directed at the horizontal development of an oil and liquids-rich resource play in the STACK. The STACK is a prolific hydrocarbon system with high oil and liquids-rich natural gas content, with potential for multiple horizontal target horizons, extensive production history and high drilling success rates. We generally maintain operational control of the majority of our properties, either through directly operating them or through operating arrangements with other interest owners.

As of December 31, 2018, we have assembled a highly contiguous position of140,400 net acres in the up-dip, naturally-fractured oil portion of the STACK, primarily in eastern Kingfisher and southeastern Major Counties in Oklahoma. Our drilling locations primarily target the Osage, Meramec and Oswego formations. After the Business Combination, we conducted

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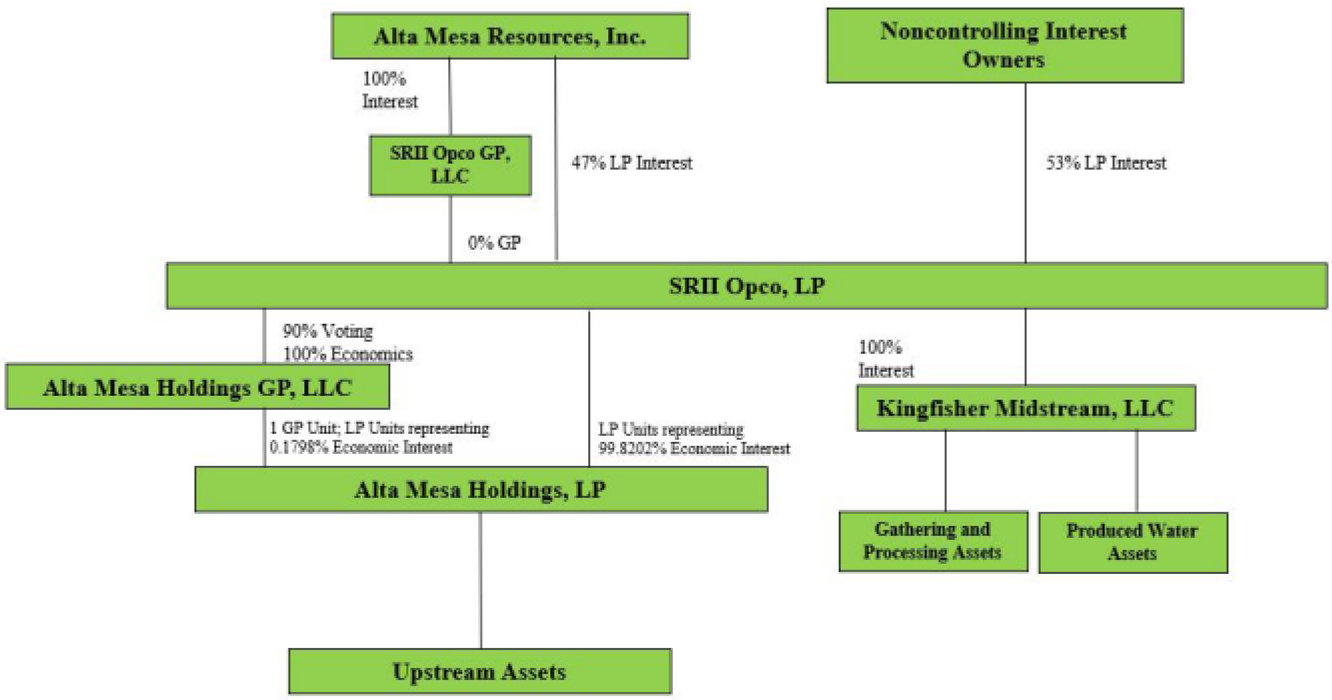
development activities using a spacing array of 6 to 10 wells per section and running up to 9 rigs at the peak activity level. In late 2018, our production across the acreage evidenced that the well spacing was not delivering the well level production that we expected. During January 2019, we suspended our development program to allow our new management team to conduct a full operational and economic review. We restarted our development program in March 2019 with a less dense spacing pattern of up to five wells per section. In addition, we have worked to improve our economic returns by reducing well costs, general and administrative expense and other operating expense. We have operated 2 rigs since restarting the program, however following the redetermination of the borrowing base of the Alta Mesa RBL in August, we have decided to operate 1 rig starting in September. We will continue to evaluate how much, if any, development is appropriate going forward.

Organizational Structure

The following diagram illustrates our ownership structure as of December 31, 2018.



Business Combination

As described further in Item 8 of this Annual Report, certain transactions were consummated on February 9, 2018, that resulted in our acquisition of interests in Alta Mesa, Alta Mesa Holdings GP, LLC ("Alta Mesa GP") and KFM through a newly formed subsidiary, SRII Opco, LP ("SRII Opco"). These transactions are referred to as the "Business Combination." Prior to the closing of the Business Combination, Alta Mesa was controlled by High Mesa, Inc. ("HMI").

During the fourth quarter of 2017, Alta Mesa sold certain of its non-STACK oil and gas assets and liabilities.Immediately prior to the closing of the Business Combination, Alta Mesa distributed its remaining non-STACK oil and gas assets and liabilities to High Mesa Holdings, LP (the "AM Contributor"), such that Alta Mesa's only remaining oil and gas assets and liabilities were located in the STACK.As described elsewhere, the AM Contributor owes us a substantial sum for amounts arising before and after the Business Combination, and it has indemnified us for liabilities arising from non-STACK oil and gas assets. We believe there is substantial doubt about its ability to make payment and honor its indemnification. Information related to Alta Mesa's non-STACK oil and gas assets and liabilities that were sold or distributed is disclosed as discontinued operations in Item 8 of this Annual Report.

Pursuant to the Business Combination, we recorded the acquired assets and liabilities at their estimated fair values and pushed those values down to the financial records of our respective subsidiaries. This resulted in our financial presentation being

separated into two distinct periods - the period before the Business Combination on February 9, 2018 ("Predecessor") and the period after the Business Combination ("Successor").

Going Concern

Our present level of indebtedness and the current commodity price environment present challenges to our ability to comply with the covenants in the agreements governing our indebtedness. As a result of the decrease in our forecasted production levels compared to the forecasts at the time of the Business Combination and pressures created by lower commodity prices, in the absence of one or more deleveraging transactions, we do not anticipate maintaining compliance with the consolidated total leverage ratio covenant in the Alta Mesa RBL as early as the measurement date of September 30, 2019. In addition, we have been substantially fully utilized under the Alta Mesa RBL since April 2019 and have no meaningful remaining capital availability. Our lenders exercised their right to conduct an optional redetermination ahead of the regularly scheduled redetermination in October 2019 and have established a new borrowing base of $200.0 million, effective August 13, 2019.As provided under the Alta Mesa RBL, we have elected to repay the excess utilization in 5 equal monthly installments of $32.5 million, the first of which will be due in September 2019. If we are unable to make these deficiency payments, we would be in default under the Alta Mesa RBL.Our Board and its financial advisors are evaluating the available financial alternatives, including seeking amendments or waivers to the covenants or other provisions of our indebtedness to address our capital structure including raising new capital from the private or public markets or taking other actions either in court or out of court. If we are unable to reach an agreement with our lenders or find acceptable alternative financing, it may lead to an event of default under our debt agreements. If following an event of default, the Alta Mesa RBL lenders were to accelerate repayment, it may result in an event of default and an acceleration of the 2024 Notes. We have concluded that these circumstances create substantial doubt regarding our ability to continue as a going concern.

If an agreement is reached with our creditors and we pursue a restructuring, it may be necessary for us, or our subsidiaries, to file a voluntary petition for relief under Chapter 11 of the U.S. Bankruptcy Code in order to implement the agreement through the confirmation and consummation of a plan of reorganization approved by the bankruptcy court. We may also conclude it is necessary to initiate Chapter 11 proceedings to implement a restructuring of our obligations even if we are otherwise unable to reach an agreement with our creditors.If a plan of reorganization is implemented in a bankruptcy proceeding, it is possible that holders of claims and interests with respect to, or rights to acquire, our equity securities would be entitled to little or no recovery, and those claims and interests may be canceled for little or no consideration.If that were to occur, we anticipate that all or substantially all of the value of all investments in our equity securities would be lost and that our equity holders would lose all or substantially all of their investment. It is also possible that our stakeholders, including our secured and unsecured creditors, will receive substantially less than the amount of their claims. For a more detailed discussion, please read the Risk Factors in Item 1A.

Sale of Produced Water Assets

In November 2018, Alta Mesa sold substantially all of its produced water assets, consisting of produced water gathering pipelines, facilities, disposal wells, surface leases and easements, to a subsidiary of KFM for approximately$99 million, including approximately $90 million in cash at closing and $9 million of purchase price adjustments, which, in total, approximated the net book value of the produced water assets. Because Alta Mesa and KFM are each owned by SRII Opco, the transaction was accounted for as a transfer of assets among entities under common control and the purchase was recorded at book value by KFM. In conjunction with the sale, Alta Mesa entered into a new 15-year produced water agreement with KFM.

Principal Products, Markets and Customers

Our Upstream segment sells our production to customers generally at prevailing spot prices in effect at the time of the sale. Our Midstream segment derives its revenue from fees assessed for gathering and processing natural gas, gathering and transporting oil, the sale of processed residue gas and NGLs and produced water gathering and disposal services. Natural gas is processed on behalf of the producer and the resulting gas, condensate and NGLs are sold at market prices. We remit to the producer an agreed-upon price from the resulting sales, which is treated as product expense. Collateral or other security is generally not required with regard to our trade receivables.

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Much of our oil and gas production in 2018, including certain processed gas and NGLs, was sold through a marketing agreement with ARM Energy Management, LLC (“ARM”), who marketed and sold our oil and gas production and processed products under short-term contracts, generally with month-to-month pricing based on published indices, adjusted for transportation, location and quality.ARM generally remitted monthly collections of these sales to us, net of its fee. For the Successor Period, ARM marketed $336.2 million, or 71% of our total operating revenue for the period.

Effective as of June 1, 2019, we have terminated our oil and NGL marketing agreement with ARM and will market such products internally.We have extended the term of our gas marketing agreement with ARM through November 30, 2019.With respect to gas sales, ARM continues to collect payments from purchasers, deducts their marketing fee and remits the balance to us.

We also sell our NGL production under various contracts with processors in the vicinity of the production at spot market rates, after processing costs. Other than our marketing agreement with ARM, no other customers accounted for more than 10% of our consolidated sales for the Successor Period. We do not believe the loss of any specific customer, or of our marketing agent ARM, would have a material adverse effect on us because alternative purchasers are available.

The oil and gas production from our operated STACK acreage, not otherwise previously dedicated, is dedicated to KFM for midstream services.

Upstream Segment Operating Summary

?	Successor	Predecessor		
?	February 9, 2018 Through December 31, 2018	January 1, 2018 Through February 8, 2018	Year Ended December 31, 2017	Year Ended December 31, 2016
Net production:				
Oil (Mbbls)	5,053	494	3,907	2,571
Natural gas (MMcf)	16,913	1,609	13,972	8,259
NGLs (Mbbls)	2,268	151	1,277	824
Total (MBoe)	10,140	914	7,513	4,772
Daily average (MBoe)	31.1	23.4	20.6	13.1
Average sales prices (pre-hedging):				
Oil (per bbl)	$ 63.99	$ 62.68	$ 49.76	$ 41.15
Natural gas (per Mcf)	2.57	2.66	2.70	2.42
NGLs (per bbl)	18.98	26.41	24.62	17.21
Combined (per Boe)	40.41	42.95	35.10	29.35
Average sales prices (after hedging):				
Oil (per bbl)	$ 56.64	$ 56.24	$ 49.42	$ 73.25
Natural gas (per Mcf)	2.42	3.60	3.19	3.21
NGLs (per bbl)	18.98	26.41	23.48	16.81
Combined (per Boe)	36.51	41.13	35.64	47.93
Average costs per BOE:				
Lease operating expense	$ 5.97	$ 4.82	$ 5.85	$ 6.20
Marketing and transportation expense	4.93	4.08	3.92	2.44
Production and ad valorem taxes	1.66	1.04	0.73	0.58
Workover expense	0.55	0.46	0.57	0.72

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Midstream Segment Operating Summary

?		Successor
		February 9, 2018 Through December 31, 2018
Net throughput:		
KFM gas volumes (MMcf)		35,058
KFM crude oil gas volumes (Mbbls)		1,739
KFM produced water gathering volumes (Mbbls)		5,320
(In thousands)		
Revenues:		
Sales of gathered production	$	31,506
Midstream revenue		68,519
Total Midstream sales revenue	$	100,025
Expenses:		
Midstream operating	$	15,221
Cost of sales for purchased gathered production		31,247
Transportation and processing		9,911
Depreciation and amortization		27,388
Impairment of assets:		
Impairment of Cimarron investment		15,963
Impairment of property, plant and equipment		68,407
Impairment of intangible assets		394,999
Impairment of goodwill		691,970
Total Midstream impairment of assets		1,171,339
General and administrative		14,025
Total operating expenses	$	1,269,131

Seasonality

Weather conditions affect the demand for, and prices of, oil and gas. During the winter, natural gas demand for heating by residential and commercial consumers generally increases whereas high summer temperatures can result in an increase in demand from the power sector.Natural gas in storage typically increases from April through October. Crude oil markets tend to be stronger in the fourth quarter when demand for heating oil is impacted by colder weather and inventory build. Hurricanes and other severe weather (particularly along the Gulf Coast) can also impact supplies by causing disruptions in the level of oil and gas production. Due to these fluctuations, results of operations for individual quarterly periods may not be indicative of the results that may be realized on an annual basis.

Competition

We compete with other companies in all areas of our operations, including the acquisition of producing properties and undeveloped acreage.Our competitors include major integrated oil and gas companies and independent oil and gas companies. Many of our competitors are large, well-established companies with substantially greater resources and better credit than us and have been engaged in the oil and gas business for a longer period of time than we have. This may allow our competitors to have an advantage over us with respect to:

- acquisitions of oil and gas properties, exploratory prospects and mineral leases;
- evaluations of properties;
- utilization of midstream assets; and

- absorption of price changes and the costs and implementation of evolving federal, state and local laws and regulations.

We are also affected by competition for drilling rigs and other equipment, including that used in our completion process.In the past, the oil and gas industry has experienced shortages of drilling rigs, equipment, pipe, materials (including drilling and completion fluids) and personnel.These shortages can delay our development, exploitation and exploration activities. We are unable to predict when, or if, such future shortages will occur or their impact on our operations.

With decreased activity in the STACK since 2018, we have seen opportunities to renegotiate our service costs. We believe that we can continue to drive service costs down or maintain the savings that we have captured during 2019, unless there is a spike in commodity prices and industry activity or heightened concerns about our creditworthiness.

Regulatory Environment

Our Upstream and Midstream operations are subject to stringent federal, state and local laws and regulations governing occupational safety and health, the discharge of materials into the environment and environmental protection. Numerous governmental agencies, including the U.S. Environmental Protection Agency ("EPA") and analogous state agencies have the power to enforce compliance with these laws and regulations and the permits issued under them, often requiring difficult and costly actions. Among other things, these laws and regulations may:

- require various permits before drilling and other regulated activities commence;
- require installation of pollution control equipment and place other conditions on our operations;
- place restrictions on the use of materials for our operations and upon the disposal of by-products from our operations;
- restrict the types, quantities and concentrations of various substances that can be released into the environment or used for our operations;
- limit our operations on lands lying within wilderness, wetlands and other protected areas;
- require remedial measures to mitigate pollution from former and ongoing operations, including site restoration, pit closure and plugging of abandoned wells; and
- impose specific safety and health criteria addressing worker protection.

These laws, rules and regulations often impose difficult and costly compliance measures that carry substantial administrative, civil and criminal penalties and may result in remedial or corrective action obligations.

Resource Conservation and Recovery Act

The federal Resource Conservation and Recovery Act ("RCRA") and comparable state statutes regulate the generation, transportation, treatment, storage, disposal and cleanup of non-hazardous and hazardous wastes. Pursuant to rules issued by the EPA, the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. As part of our operations, we generate some amounts of ordinary industrial wastes that may be deemed as hazardous wastes by regulatory authorities. Drilling fluids, produced waters, and most of the other wastes associated with our operations, if properly handled, are currently exempt from regulation as hazardous waste under RCRA and, instead, are regulated under RCRA's less stringent non-hazardous waste provisions, state laws or other federal laws. However, it is possible that regulations could change and cause wastes now classified as non-hazardous to be classified as hazardous wastes.

Comprehensive Environmental Response, Compensation and Liability Act

The federal Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA"), also known as the Superfund law, and comparable state laws impose liability on classes of persons considered to be responsible for the release of hazardous substances and other classes of materials. Under CERCLA, such persons may be subject to joint and several, strict liability for costs of investigation and remediation and for damages without regard to fault or legality of the original conduct. These classes of persons, dubbed potentially-responsible-parties ("PRPs") include the current and past owners or operators of a site where the hazardous substance release occurred and anyone who disposed or arranged for the disposal of a hazardous substance released at the site. CERCLA also authorizes the EPA and, in some instances, third parties to take actions in response to threats to public health or the environment and to seek to recover from the PRPs the costs of such action. Many states have adopted comparable statutes.

Federal Water Pollution Control Act

The Federal Water Pollution Control Act, also known as the Clean Water Act ("CWA") and analogous state laws impose restrictions and controls regarding the discharge of pollutants into state and federal waters. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or an analogous state agency. Spill prevention, control and countermeasure plan requirements imposed under the CWA require appropriate containment berms and similar structures to help prevent the contamination of regulated waters in the event of a spill, rupture or leak. In addition, the CWA and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities.

Safe Drinking Water Act

Our underground injection operations are regulated pursuant to the Underground Injection Control ("UIC") program established under the federal Safe Drinking Water Act ("SDWA") and analogous state and local laws and regulations. The UIC program includes administrative requirements for produced water disposal and prohibits migration of fluid containing any contaminant into underground sources of drinking water. State regulations require permits to operate underground injection wells. Although we monitor the injection process of our wells, any leakage from the subsurface portions of the injection wells could cause degradation of fresh groundwater resources, potentially resulting in suspension of our UIC permit, issuance of fines and penalties from governmental agencies, incurrence of expenditures for remediation of the affected resource and imposition of liability by third-parties claiming damages for alternative water supplies, property and personal injuries. A change in UIC disposal well regulations or the inability to obtain permits for new disposal wells in the future may affect our ability to dispose of produced waters and other substances, which could affect our business.

Furthermore, in response to recent seismic events near produced water disposal wells, federal and some state agencies are investigating whether such wells have contributed to increased seismic activity, and some states have restricted, suspended or shut down the use of such disposal wells. In response to these concerns, regulators in some states have imposed, or are considering imposing, additional requirements in the permitting of produced water disposal wells or otherwise to assess any relationship between seismicity and the use of such wells. For example, Oklahoma issued new rules for injection wells in 2014 that imposed certain permitting and operating restrictions and reporting requirements on disposal wells in proximity to faults and also, from time to time, has developed and implemented plans directing certain wells where seismic incidents have occurred to restrict or suspend disposal well operations.

Clean Air Act

Our operations are subject to the federal Clean Air Act ("CAA") and comparable state laws and regulations that restrict the emission of air pollutants. These laws and regulations may require us to obtain approval for the construction or modification of certain facilities expected to produce or significantly increase air emissions, comply with stringent air permit requirements and also utilize equipment or technologies to control emissions. Obtaining such permits could delay our operations.

National Environmental Policy Act

Our operations on federal lands may be subject to the federal National Environmental Policy Act ("NEPA"), which requires federal agencies, including the EPA, to evaluate major agency actions having the potential to significantly impact the environment. As part of such evaluations, an agency will conduct an environmental assessment that assesses the potential impacts of a proposed project and may require a detailed environmental impact statement for public review and comment. Our current and future operations on federal lands will be subject to NEPA, which could delay or impose additional conditions and costs on us. Moreover, this process could experience protest, appeal or litigation, any or all of which may impact our operations.

Occupational Safety and Health Act

We are subject to the requirements of the federal Occupational Safety and Health Act and comparable state statutes whose purpose is to protect the health and safety of workers. In addition, comparable state statutes require that we organize and/or disclose information about hazardous materials attendant to our operations to our employees, state and local governmental authorities and citizens.

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Our processing plant operations are also subject to standards designed to ensure the safety of our processes, such as the Occupational Safety and Health Administration's Process Safety Management standard, which is designed to prevent or minimize the consequences of catastrophic releases of toxic, reactive, flammable or explosive chemicals. The Process Safety Management standard imposes requirements on regulated entities related to managing these hazards. These requirements include conducting process hazard analyses for processes involving highly hazardous chemicals, developing detailed written operating procedures, including procedures for managing change, and evaluating the mechanical integrity of critical equipment. We conduct periodic audits of Process Safety Management systems at each of our locations subject to this standard.

Hydraulic Fracturing

We perform hydraulic fracturing in horizontally drilled wells. Currently, most of our hydraulic fracturing activities are regulated at the state level as the EPA only has limited purview over fracturing activities. However, several federal agencies have asserted regulatory authority or pursued investigations over certain aspects of the hydraulic fracturing process. For example, in December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources, concluding that "water cycle" activities associated with hydraulic fracturing may impact drinking water resources "under some circumstances," including water withdrawals for fracturing in times or areas of low water availability; surface spills during the management of fracturing fluids, chemicals or produced water; injection of fracturing fluids into wells with inadequate mechanical integrity; injection of fracturing fluids directly into groundwater resources; discharge of inadequately treated fracturing wastewater into surface waters; and disposal or storage of fracturing wastewater in unlined pits.

Climate Change Regulations and Legislation

Climate change continues to attract considerable public and scientific attention. As a result, numerous proposals have been made and are likely to continue to be made at all levels of government to monitor and limit emissions of greenhouse gases ("GHGs"). These efforts have included consideration of cap-and-trade programs, carbon taxes, GHG reporting and tracking programs and regulations that directly limit GHG emissions from certain sources.

At the federal level, no comprehensive climate change legislation has been implemented to date. The EPA has, however, adopted regulations that, among other things, establish Potential for Significant Deterioration ("PSD") construction and Title V operating permit reviews for GHG emissions from certain large stationary sources that are already potential sources of significant pollutant emissions. Sources subject to these permitting requirements must meet "best available control technology" standards for those GHG emissions. Additionally, the EPA has adopted rules requiring the monitoring and annual reporting of GHG emissions from specified GHG emission sources in the United States, including, among others, onshore and offshore oil and gas production, processing, transmission, storage and distribution facilities, which include certain of our operations.

Federal agencies also directly regulate emissions of methane, a GHG, from oil and gas operations. In August 2016, the EPA issued a final New Source Performance Standards ("NSPS") rule, known as Subpart OOOOa, which requires certain new, modified or reconstructed facilities in the oil and gas sector to reduce these methane gas and volatile organic compound emissions. These Subpart OOOOa standards expand previously issued NSPS published by the EPA in 2012, and known as Subpart OOOO, by using certain equipment-specific emissions control practices.

Other Regulation of the Oil and Gas Industry

Our operations are also subject to various other types of regulation at the federal, state and local level. These types of regulations include requiring permits for the drilling of wells, drilling bonds and reports concerning operations. The state, and some counties and municipalities, in which we operate may also regulate:

- the location of wells;
- the method of drilling and casing wells;
- the timing of conducting our activities, including seasonal wildlife closures;
- the rates of production;
- the surface use and restoration of properties where we operate;
- the plugging and abandoning of wells;
- interactions with surface owners and other third parties; and
- abandonment of pipelines and midstream facilities.

State laws regulate the size and shape of drilling and spacing units or proration units governing the pooling of oil and gas properties. We rely upon the Oklahoma "forced pooling" process to facilitate working interest owners' participation in our operations. Under this process, if a party proposes to drill the initial well to a particular formation in a specific drilling and spacing unit but cannot obtain the agreement of all other oil and gas interest holders and other leaseholders within the unit as to how the unit should be developed, the party may initiate "forced pooling". Under current regulations, drilling and spacing units for our targeted horizons are based on a maximum of four to eight horizontal wells, depending on the formation, on a 640-acre section. In a forced pooling action, the proposed operator files an application for a pooling order with the Oklahoma Corporation Commission ("OCC") and names all other persons with the right to drill the unit as respondents. The proposed operator is required to demonstrate that it has made a good faith effort to bargain with all of the respondents prior to filing its application. The fair value of the mineral interests in the unit is determined in an administrative proceeding by reference to market transactions involving nearby oil and gas rights, including nearby mineral lease costs.

Assuming the application for a forced pooling order is granted, the respondents then have 20 days to elect either to participate in the proposed well or accept fair value for their interest, usually in the form of a cash payment, an overriding royalty, or some combination, based on the fair value established and approved through the administrative hearing. The pooling order typically addresses the time frame for drilling the well and provides for the manner in which future wells within the unit may be drilled. The applicant for the pooling order is ordinarily designated as the operator of the wells subject to the pooling order.

The availability of forced pooling normally means that it is difficult for a small number of owners to block or delay the drilling of a particular well proposed by another interest holder. Oil and gas companies in Oklahoma generally attempt to lease as much of the mineral interests in a particular area as are readily available at acceptable rates, and then use the forced pooling process to proceed with the desired development of the well. In this manner, we have the ability to expand into and develop areas near our existing acreage even if we are unable to lease all of the mineral interests in those areas.

The gross production tax, or severance tax, is a value-based tax levied at a basic rate of 7% upon the production of oil and gas in Oklahoma. As an economic incentive to develop its resources, Oklahoma has historically offered a "tax holiday" with rates ranging from 1% for 48 months to 2% for 36 months for production from horizontal wells. Through June 2018, Oklahoma imposed a tax of 2% of gross production for the first 36 months of production and then at 7% thereafter on wells drilled after July 1, 2015. Effective July 2018, the 2% tax rate was increased to 5% for wells drilled after July 1, 2015 that were still within their first 36 months of production. For the period beyond 36 months, the tax rate remains at 7% for the remaining productive life of each well. All wells drilled after July 1, 2018 are taxed at 5% of gross production for the first 36 months of production and then at 7% thereafter. In addition, a longstanding excise tax of 0.095% continues to be levied.

Federal, state and local regulations provide detailed requirements for the abandonment of wells, closure or decommissioning of production facilities and pipelines and for site restoration in areas where we operate. The U.S. Army Corps of Engineers and many other state and local authorities also have regulations covering these procedures. Some state agencies and municipalities have binding requirements related thereto.

Regulation of Natural Gas Sales and Transportation

The rates, terms and conditions applicable to the interstate transportation of oil and natural gas liquids by pipelines are regulated by the Federal Energy Regulatory Commission (the "FERC"), as common carriers, under the Interstate Commerce Act. The FERC has implemented a simplified and generally applicable ratemaking methodology for interstate oil and natural gas liquids pipelines to fulfill the requirements of Title XVIII of the Energy Policy Act of 1992 comprised of an indexing system to establish ceilings on interstate oil and natural gas liquids pipeline rates. Intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates, varies from state to state. Insofar as effective interstate and intrastate rates are equally applicable to all comparable shippers, we believe that the regulation of oil transportation rates will not affect our operations in any materially different way than such regulation will affect the operations of our competitors.

The pipelines used to gather and transport natural gas being produced by us are also subject to regulation by the U.S. Department of Transportation ("DOT") under the Natural Gas Pipeline Safety Act of 1968, as amended, the Pipeline Safety Act of 1992, as reauthorized and amended ("Pipeline Safety Act"), and the Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011. The DOT Pipeline and Hazardous Materials Safety Administration ("PHMSA") has established a risk-based approach to determine which gathering pipelines are subject to regulation and what safety standards regulated gathering pipelines must meet. In March 2016, the PHMSA issued a Notice of Proposed Rulemaking proposing to revise the Pipeline

Safety Regulations applicable to the safety of onshore gas transmission and gathering pipelines, including both high consequence areas (“HCAs”) and non-HCAs.

Any transportation of our crude oil, natural gas liquids and purity components (ethane, propane, butane, iso-butane and natural gasoline) by rail is also subject to regulation by the DOT’s PHMSA, and the DOT’s Federal Railroad Administration (“FRA”) under the Hazardous Materials Regulations at 49 CFR Parts 171-180, including Emergency Orders by the FRA and new regulations being proposed by the PHMSA, arising due to the consequences of train accidents and the increase in the rail transportation of flammable liquids.In October 2015, the PHMSA issued proposed new safety regulations for hazardous liquid pipelines, including a requirement that all hazardous liquid pipelines have a system for detecting leaks and establish a timeline for inspections of affected pipelines following extreme weather events or natural disasters.

Gathering Pipeline Regulation

Section 1(b) of the Natural Gas Act of 1938 (“NGA”), exempts natural gas gathering facilities from regulation by the FERC under the NGA.We believe that our Midstream assets meet the tests the FERC has used to determine exemption from its jurisdiction.

Other

The oil and gas industry is also subject to other federal, state and local regulations and laws relating to resource conservation and employment standards.

Employees

As of June 28, 2019, we had 154 full-time employees. We are not a party to any collective bargaining agreements and have not experienced any strikes or work stoppages.

Insurance

We maintain customary insurance against some, but not all, of the operating risks to which our business is exposed. We currently have policies in place that cover general liability (includes sudden and accidental pollution), physical damage to our assets, control of wells, auto liability, worker’s compensation and employer’s liability.

We regularly execute master services contracts with our third-party vendors, suppliers and contractors in which they agree to indemnify us for injuries and deaths of their employees and contractors. Similarly, we generally agree to indemnify them against claims made by our other vendors, suppliers, contractors and employees. Additionally, each party generally is responsible for damage to its own property.

Executive Officers

Our executive officers and their ages as of July 31, 2019, are set forth below:

Name	Age	Position
James T. Hackett	65	Executive Chairman of the Board and Interim Chief Executive Officer
Randy L. Limbacher	61	Interim President
John C. Regan	49	Executive Vice President, Chief Financial Officer and Assistant Secretary
John H. Campbell, Jr.	61	Interim Executive Vice President and Chief Operating Officer
Kimberly O. Warnica	45	Executive Vice President, General Counsel, Chief Compliance Officer and Secretary
Mark P. Castiglione	48	Interim Executive Vice President - Strategy and Corporate Development

James T. Hackett became our Executive Chairman of the Board immediately following the closing of the Business Combination and was named Interim Chief Executive Officer on December 26, 2018. He also briefly served as Chief Operating Officer— Midstream from February 9, 2018 until April 2018 and now serves as President of the Company’s subsidiary KFM. Prior to the Business Combination, he served as our Chief Executive Officer and director since March 2017. Mr. Hackett is a Senior Advisor to Riverstone Investment Group, LLC. Prior to joining Riverstone in 2013, Mr. Hackett served as the Chairman of the Board from 2006 to 2013 and the Chief Executive Officer from 2003 to 2012 of Anadarko Petroleum Corporation.

Before joining Anadarko, Mr. Hackett served as President and Chief Operating Officer of Devon Energy Corporation, following its merger with Ocean Energy, where he had served as Chairman, President, and Chief Executive Officer. Mr. Hackett has held senior positions at Seagull, Duke Energy, and Pan Energy. He also held positions in engineering, finance and marketing in the midstream, oil field services, and power sectors of the energy industry. Mr. Hackett serves on the Board of Directors of Enterprise Products Holdings, LLC, Fluor Corporation and National Oilwell Varco, Inc. Mr. Hackett is a former Chairman of the Board of the Federal Reserve Bank of Dallas. Mr. Hackett received a Bachelor of Science degree from the University of Illinois in 1975 and an MBA and MTS from Harvard University in 1979 and 2016, respectively.

Randy L. Limbacher became our Interim President on January 1, 2019. He also serves as the Chief Executive Officer of Meridian Energy LLC (a Houston-based energy advisory firm), a position he has held since June 2017. He currently serves on the board of directors of CARBO Ceramics Inc. and TC Energy Corporation (formerly TransCanada Corporation). From March 2017 to June 2017, Mr. Limbacher managed his personal investments as a private investor. From April 2013 until December 2015, Mr. Limbacher served as President, Chief Executive Officer and a Director of Samson Resources Corporation, a Tulsa-based oil and gas company, which filed for Chapter 11 protection in September 2015. Mr. Limbacher served as Vice Chairman of the Board of Directors of Samson from December 2015 until the company emerged from bankruptcy in March 2017. From November 2007 until February 2013, Mr. Limbacher served as President and Chief Executive Officer and a Director of Rosetta Resources, Inc., a Houston-based oil and gas company. From February 2010 until February 2013, Mr. Limbacher also served as Chairman of the Board of Rosetta. From April 2006 until November 2007, Mr. Limbacher held the position of President, Exploration and Production - Americas for ConocoPhillips, a Houston-based energy company. Prior to that time, Mr. Limbacher spent over twenty years with Burlington Resources Inc., a Houston-based oil and gas company, where he served as Executive Vice President and Chief Operating Officer from 2002 until it was acquired by ConocoPhillips in April 2006. He was a Director of Burlington Resources from January 2004 until the sale of the company.Mr. Limbacher received a Bachelor of Science degree in petroleum engineering from Louisiana State University in 1980.

John C. Regan was named Executive Vice President, Chief Financial Officer and Assistant Secretary on June 18, 2019. Prior to joining us as Vice President, Chief Financial Officer and Assistant Secretary on January 7, 2019, Mr. Regan served as the Chief Financial Officer of Vine Oil and Gas LP from January 2015 to June 2018. He previously served as Chief Financial Officer of Quicksilver Resources from April 2012 through December 2014, after having served as their Chief Accounting Officer beginning in September 2007. Mr. Regan is a Certified Public Accountant with more than 25 years of combined public accounting, corporate finance and financial reporting experience.

John H. Campbell, Jr. became our Interim Executive Vice President and Chief Operating Officer on June 18, 2019.Mr. Campbell initially joined us on January 1, 2019 as Interim Chief Operating Officer - Upstream.He also serves as President and Chief Operating Officer of Meridian Energy LLC, a position he has held since June 2017. From June 2016 to June 2017, Mr. Campbell served as a partner of Quantum Energy Partners, LLC. Prior to joining Quantum Energy Partners, LLC, he served as President of QL-Energy, LLC. From 2010 to 2014, Mr. Campbell served as President and Chief Operating Officer of QR Energy, LP. From 2008 to 2015 Mr. Campbell served as President and Chief Operating Officer of Quantum Resources Management, LLC. Mr. Campbell received a Bachelor of Science degree in petroleum engineering from the University of Alabama, Tuscaloosa in 1983 and a Master of Engineering degree in petroleum engineering degree from Texas A&M University in 1987.

Kimberly O. Warnica was named Executive Vice President, General Counsel, Chief Compliance Officer and Secretary on June 18, 2019.Ms. Warnica initially joined us in April 2018 as our Vice President, General Counsel, Chief Compliance Officer and Secretary. Prior to joining us, Ms. Warnica served as Assistant General Counsel and Assistant Secretary at Marathon Oil Corporation since April 2017. She previously served as Group Counsel and Assistant Secretary of Marathon Oil from October 2016 until April 2017. Prior to Marathon Oil, Ms. Warnica served as Assistant General Counsel and Assistant Secretary at Freeport-McMoRan Oil & Gas (formerly Plains Exploration and Production Company) from April 2006 until June 2016. She started her career at Andrews Kurth LLP where she practiced corporate and securities law representing a variety of clients in numerous transactional, securities and corporate governance matters. Ms. Warnica has a Bachelor's degree from Texas A&M University and earned her J.D. from the University of Texas School of Law.

Mark P. Castiglione became our Interim Executive Vice President - Strategy and Corporate Development on June 18, 2019.He initially joined us as Chief of Staff to the President on January 1, 2019.He also serves as Executive Vice President of Meridian Energy LLC, a position he has held since June 2017. From January 2015 to May 2017, Mr. Castiglione managed MPC Resources, LLC (an energy advisory firm) and was engaged as Senior Advisor to SandRidge Energy, Inc. from January 2015 to June 2016. From 2010 to December 2014, he served as Senior Vice President – Business Development of Quantum Resources Management, LLC and QR Energy, LP. Prior to joining Quantum Resources, Mr. Castiglione served as Vice President –

Acquisitions and Divestitures of El Paso Corporation from 2009 to 2010 and Vice President – Business Development of El Paso Exploration and Production from 2008 to 2009. Mr. Castiglione's prior background at Encana Corporation, Burlington Resources and Simmons & Company International includes positions of increasing responsibility in corporate development, corporate finance, asset management and engineering. He began his career in 1994 as a reservoir engineer at Burlington Resources. Mr. Castiglione received a Bachelor of Science degree in petroleum engineering from Texas Tech University in 1993 and a Master of Business Administration degree from the Cox School of Business at Southern Methodist University in 1999.

Available Information

We periodically disseminate information about the Company through required filings we make with the SEC and, at our discretion, on our website at www.altamesa.net. Information contained on or connected to our website is not incorporated by reference into this Annual Report and should not be considered part of this Annual Report or any other filings we make with the SEC.The SEC maintains a site that contains reports, proxy and information statements and other information regarding reporting issuers.Our annual reports on Form 10-K, quarterly reports on Form 10-Q and current reports on Form 8-K are filed electronically and are available free of charge athttp://www.sec.gov. Additionally, the Company will provide electronic or paper copies free of charge upon request to our Secretary at 15021 Katy Freeway, Suite 400, Houston, Texas 77094 or by calling (281) 530-0991.

Item 1A. Risk Factors

Investing in our securities involves a high degree of risk. You should consider carefully the risks and uncertainties described below, together with all of the other information in this Annual Report, including our consolidated financial statements and related notes, before deciding whether to purchase any of our securities.

Each of the following risk factors could adversely affect our business, operating results and financial condition (which we individually and/or collectively refer to as having "an adverse effect on us." It is not possible to foresee or identify all such factors. Investors should not consider this list as an exhaustive statement of all risks and uncertainties. This report also contains forward-looking statements that involve risks and uncertainties. Our actual results may differ from those anticipated in these forward-looking statements as a result of both the risks described below and factors described elsewhere in this Annual Report. Please read the section above entitled "Cautionary Statement Regarding Forward-Looking Statements" for further discussion of these matters.

Going Concern Risk

Our ability to continue as a going concern contemplates the realization of assets and the satisfaction of liabilities in the normal course of business, including the effective implementation and success of our plans to mitigate the conditions that raise substantial doubt about our ability to continue as a going concern.

Our consolidated financial statements have been presented on the basis that we would continue as a going concern, which contemplates the realization of assets and satisfaction of liabilities in the normal course of business. Our liquidity and ability to comply with debt covenants under the Alta Mesa RBL and the KFM Credit Facility have been negatively impacted by increased borrowings, the recent decrease in forecasted production levels and increased operating costs in 2018 in our Upstream business, in addition to the pressures created by lower commodity prices in late 2018 and early 2019. Additionally, we failed to timely provide our lenders under the KFM Credit Facility with quarterly financial statements for the quarter ended December 31, 2018, and we failed to provide our lenders notice in connection with KFM's acquisition of the produced water assets from Alta Mesa, including the delivery of certain recorded instruments of transfer.In April 2019, we entered into an amendment and limited waiver (the "Amendment") to the KFM Credit Facility to waive the defaults and events of default arising or resulting from those failures. The Amendment adds provisions which limit the maximum amount of cash KFM can hold to $15.0 million.The Amendment also generally provides that any amendment to a material contract with an affiliate during a six-month period that causes a reduction to projected revenue by more than 15% constitutes an event of default. We also subsequently provided the lenders the required quarterly financial statements and recorded instruments of transfer in connection with the Amendment.

Based on our current operating and commodity price forecast and our current capital structure, and in the absence of the consummation of one or more of the deleveraging transactions discussed below, we do not anticipate being able to maintain compliance with the consolidated total leverage ratio covenant in the Alta Mesa RBL as early as the measurement date of September 30, 2019. In August 2019, the lenders exercised their ability to make an optional redetermination of the borrowing base under the Alta Mesa RBL ahead of the regular redetermination scheduled in October 2019, and via this redetermination, our borrowing base was reset to $200.0 million effective August 13, 2019. As our combined borrowings and letters of credit outstanding exceed the new borrowing base by $162.4 million, we have five months to make ratable payments of $32.5 million each month to cause utilization to be less than or equal to the borrowing base. If we are unable to make this repayment, we will be in default under the Alta Mesa RBL. The uncertainty related to our continued compliance with the terms of the Alta Mesa RBL and the potential for lenders under the Alta Mesa RBL to further reduce the borrowing base raise substantial doubt regarding Alta Mesa's ability to continue as a going concern. Should Alta Mesa be required to seek protection under laws governing bankruptcy before July 2020, we believe there is a risk that it or the courts could attempt to reject or alter agreements between KFM and Alta Mesa that would cause KFM's consolidated revenues to be negatively impacted by more than 15%, which would constitute an event of default under the KFM Credit Facility, as amended, giving our lenders the ability to accelerate repayment of all outstanding amounts. The consolidated financial statements do not reflect any adjustments that might result if we are unable to continue as a going concern, however we have reclassified all of Alta Mesa's debt as current liabilities.

In March 2019, our Board authorized the retention of financial advisors to assist in evaluating the available financial alternatives, including without limitation:

- amending or waiving the covenants or other provisions of our debt;
- raising new capital in private or public markets; and
- taking other actions to address our balance sheet either in court or through an out of court agreement with creditors.

We are also considering operational matters such as reducing our forecasted capital plan. Any action or combination of such actions may be unsuccessful in attaining compliance with the covenants under the Alta Mesa RBL and the KFM Credit Facility.

If an agreement is reached with our creditors and we pursue a restructuring, it may be necessary for us, or our subsidiaries, to file a voluntary petition for relief under Chapter 11 of the U.S. Bankruptcy Code in order to implement the agreement through the confirmation and consummation of a plan of reorganization approved by the bankruptcy court in the bankruptcy proceedings. We also may conclude that it is necessary to initiate Chapter 11 proceedings to implement a restructuring of our obligations even if we are unable to reach an agreement with our creditors and other relevant parties regarding the terms of such a restructuring. If a plan of reorganization is implemented in a bankruptcy proceeding, it is possible that holders of claims and interests with respect to, or rights to acquire, our equity securities would be entitled to little or no recovery, and those claims and interests may be canceled for little or no consideration. If that were to occur, we anticipate that all or substantially all of the value of all investments in our equity securities would be lost and that our equity holders would lose all or substantially all of their investment. It is also possible that our stakeholders, including our secured and unsecured creditors, will receive substantially less than the amount of their claims.

Risks Related to our Upstream Business

Oil, gas and NGL prices are highly volatile and a sustained decrease in prices can significantly and adversely affect our financial condition, results of operations and the carrying value of our assets.

Historically, the markets for oil, gas and NGLs have been volatile and are likely to continue to be volatile in the future, causing prices to fluctuate widely. Factors influencing the prices of oil, gas and NGLs are beyond our control. These factors include, but are not limited to, the following:

- domestic and worldwide supply of, and demand for, oil, gas and NGLs;
- volatility and trading patterns in the commodity-futures markets;
- the cost of exploring for, developing, producing, transporting and marketing oil, gas and NGLs;
- the level of global oil and gas inventories;
- weather conditions;
- the level of U.S. exports of oil, LNG or NGLs;
- the ability of the members of OPEC and other producing nations to agree to and maintain production levels;

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- the worldwide military and political environment, civil and political unrest worldwide, including in Africa and Middle East, uncertainty or instability resulting from the escalation or additional outbreak of armed hostilities, or acts of terrorism in the United States or elsewhere;
- the effect of worldwide energy conservation and environmental protection efforts;
- the price and availability of alternative and competing fuels;
- the value of the dollar relative to the currencies of other countries;
- the level of foreign imports of oil, gas and NGLs;
- domestic and foreign governmental laws, regulations and taxes;
- stockholder activism or activities by non-governmental organizations to limit certain sources of funding for the energy sector or restrict the exploration, development and production of oil and gas;
- the proximity to, and capacity of, gas pipelines and other transportation facilities; and
- general economic conditions worldwide.

The long-term effects of these and other factors on the prices of oil, gas and NGLs are uncertain.Historical declines in commodity prices have adversely affected our business by:

- reducing the amount of oil, gas and NGLs that we can produce economically;
- reducing our liquidity, revenue, operating income and cash flows;
- causing us to reduce our capital expenditures and delay or postpone some of our capital projects;
- causing reductions to the Alta Mesa RBL borrowing base, which negatively impacts our borrowing ability;
- causing contraction of available trade credit;
- pressuring our ability to meet financial covenants under our debt agreements;
- triggering impairments of our long-lived assets;
- reducing the value of our future net cash flows from our oil and gas properties;
- increasing the costs of obtaining capital, such as equity and short- and long-term debt; and
- adversely affecting the ability of our partners to fund their working interest capital requirements.

In April 2019, we removed all of our PUD reserves effective as of December 31, 2018, due to our assessment of our potential inability to fund the associated development costs. Lower oil, gas and NGL prices and any corresponding reduction in our capital expenditure budget and drilling program could cause us to further reduce our estimates of production, which could reduce the value of our oil and gas properties.

Our operations, including development and acquisitions, will require substantial capital expenditures.We may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a decline in our production and reserves.

Our industry is capital intensive. We have made and expect to continue to make substantial capital expenditures for the exploration, exploitation, development and acquisition of oil and gas reserves. Due to the price environment in late 2018 and early 2019, we have substantially decreased our planned capital expenditures for 2019 compared to 2018. Prior to the August 2019 redetermination of the Alta Mesa RBL, we had anticipated upstream capital expenditures for 2019 to range between $160 million to $180 million, principally for the drilling and completion of wells, expenditures for facilities and acquisition of leasehold, but we are evaluating whether this level of capital is appropriate following that redetermination. Our upstream capital expenditures for 2018 were substantially higher. Given our reduced capital plan for 2019, we are currently estimating a decline in production during the latter half of 2019. This decline in production, as well as other factors, such as lower oil, gas and NGL prices or declines in reserves may lead to reductions in our revenue and operating cash flow and may limit our ability to obtain the capital necessary to sustain our operations at desired levels, which could materially and adversely affect us.

We funded our 2018 upstream capital program primarily through equity capital raised from the Business Combination, borrowings under the Alta Mesa RBL and operating cash flow. We intend to finance our 2019 and future capital expenditures predominantly with cash flow from operations and borrowings under the Alta Mesa RBL, which we drew upon in April 2019 to substantially exhaust remaining capacity.

If necessary, and if permitted under the agreements governing our indebtedness, we may also access capital through proceeds from potential asset dispositions and the future issuance of debt and/or equity securities. Our cash flow from operations and access to capital are subject to several variables, including:

- the estimated quantities and value of our proved oil and gas reserves;
- the amount of oil and gas we produce from existing wells;

- the prices at which we sell our production; and
- our ability to acquire, locate and produce new reserves.

On April 1, 2019, in connection with a semi-annual borrowing base redetermination, our borrowing base under the Alta Mesa RBL was reduced from $400 million to $370 million, substantially all of which is currently utilized.In August 2019, the lenders exercised their option to conduct an optional redetermination, pursuant to which they established a revised borrowing base of $200.0 million, which will require us to make monthly installments of $32.5 million for five months beginning in September 2019.As a consequence of reduced operating cash flow and a lowered borrowing base, we have limited ability to obtain the capital necessary to conduct our operations at desired levels.Additionally, if we are in default under the Alta Mesa RBL, the lenders could cease making amounts available, accelerate payment of amounts outstanding or seek other remedies any of which would further limit our access to the capital necessary to fund our capital expenditures.The Alta Mesa RBL may restrict our ability to obtain new debt financing. If additional capital is required, we may not be able to obtain debt and/or equity financing on terms favorable to us, or at all. If cash generated by operations or liquidity available under the Alta Mesa RBL is not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our capital expenditures, which in turn could lead to a decline in our reserves and production, forfeiture of leasehold interests and the sale of our assets on an untimely or unfavorable basis, each of which could have a material adverse effect on us.

Our business strategy involves the use of technology, which involves risks and uncertainties in its application.

Our operations involve the use of the latest horizontal drilling, completion and production technologies in an effort to provide for more efficient or inexpensive recovery of hydrocarbons. Although our development plan for 2019 relies upon less innovation than in prior years, our use of emerging technologies may not prove successful and could result in unexpected cost increases or decreases to production or the expected recoverability of reserves and in extreme cases, the abandonment of a well. While horizontal development has become more common in our industry, we may still face difficulties in drilling horizontal wells such as:

- landing our wellbore in the desired drilling zone;
- staying in the desired drilling zone while drilling horizontally through the formation;
- running our production casing the entire length of the wellbore; and
- running tools and other equipment consistently through the horizontal wellbore.

The difficulties that we face while completing our wells include the following:

- designing and executing the optimum fracture stimulation program for a specific target zone;
- running tools through the entire length of the wellbore during completion operations; and
- cleaning out the wellbore after completion of the fracture stimulation.

Certain of the techniques may cause irregularities or interruptions in production due to offset wells being shut-in and the time required to drill and complete multiple wells before any such wells begin producing. Producing wells can be impacted by nearby completion operations which typically require nearby producing wells to de-water before production can resume. We have received, and are likely to continue to receive, claims alleging damage from our fracture and stimulation procedures on adjacent wellbores completed in the same geological interval and in other "associated" geological formations located above or below the target formation. These claims are inherently uncertain, and outcomes cannot be predicted.

Furthermore, the application of technology in one productive formation may not be successful in other prospective formations with little or no horizontal drilling history. If our use of the emerging technologies does not prove successful, our resultingproduction may be less than anticipated or we may experience cost overruns, timing delays or abandonment of a well. As a result, the return on our investment will be adversely affected and we could incur material write-downs of our assets, both of which could have a material adverse effect on us.

Our oil and gas properties are located in a limited geographic area, making us vulnerable to risks associated with having geographically concentrated operations.

Our oil and gas properties are geographically concentrated in a portion of the STACK which causes our success and profitability to be disproportionately exposed to regional factors relative to our competitors that have more geographically dispersed operations.These factors include, among others: (i) the prices of crude oil and natural gas produced from wells in the region and other regional supply and demand factors, including midstream capacity constraints; (ii) the access to and

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availability of rigs, equipment, oil field services, supplies and labor; and (iii) the availability of and access to processing and refining facilities.In addition, we may have a heightened risk to the adverse effects of severe weather events such as floods, ice storms and tornadoes, which can disrupt operations and intensify competition and risk of unavailability of the items described above.The geographic concentration of our operations also increases our exposure to changes in local laws and regulations, wildlife protection stipulations and other unexpected regional events such as natural disasters, seismic events, industrial accidents or labor difficulties. Any one of these events has the potential to disrupt our operations which could have a material adverse effect on us.

Our identified drilling locations are scheduled over many years, making them susceptible to uncertainties that could materially alter our ability to conduct development activities.

Our management team has specifically identified and scheduled the prospective drilling locations on our existing acreage.Our ability to develop our identified locations depends on a number of uncertainties, including oil, gas and NGL prices, the availability and cost of capital, drilling and production costs, availability of necessary field services and equipment, midstream constraints, access to and availability of water to conduct development, regulatory approvals and other factors. Because of these uncertainties, we do not know if the locations we have identified will ever be drilled or if we will be able to produce oil or natural gas from these locations. In addition, unless we meetthe development timing requirements on our undeveloped acreage, the leases covering such acreage may expire, causing us to lose the opportunity of future development.As such, our actual drilling activities may materially differ from our current expectations.

Our current estimated drilling locations are based on the spacing pattern that we believe will maximize the economic returns associated with development. If our expectations about well results with such spacing pattern prove incorrect, there could be a material reduction to our estimated drilling locations and inventory life.

In addition, we will require significant additional capital over a prolonged period in order to pursue the development of these locations, and we may not be able to access or raise the capital required. Any drilling activities we conduct on these locations may be unsuccessful which would limit our ability to add proved reserves or result in a downward revision of our estimated recoveries, which could have a material adverse effect on us.

Our undeveloped properties include leases that will expire over the next several years if production is not established on units containing that acreage.

Leases on oil and gas properties typically have a term of three to five years, after which they expire unless renewed or, prior to expiration, a well is drilled and production of hydrocarbons in paying quantities is established. Although the majority of our reserves are located on leases that are held by production, the leases included in our unproved properties typically have provisions whereby a lease will expire at the end of the lease term unless certain conditions are met, such as commencement of drilling or the existence of production in paying quantities within defined time periods. A reduction to our drilling program, lower commodity prices or our inability to fund our capital program could cause some of our unproved inventory to become unrealizable, be subject to lease expiration or require us to incur renewal or extension costs.The cost to renew such leases may increase significantly, and we may not be able to renew such leases on commercially reasonable terms or at all. This could result in a reduction in our acreage and growth opportunities (or the incurrence of significant costs).Our drilling plans for undeveloped acreage are also subject to change based upon various factors, including drilling results, oil, gas and NGL prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, gathering system and pipeline transportation constraints and regulatory approvals.

We depend on development of reserves and upon consummation of acquisitions to maintain our reserve base and revenue.

In general, the volume of production from oil and gas properties declines as reserves are depleted, with the rate of decline depending on each reservoir's characteristics. For example, we estimate that our base production has a decline rate of approximately 40%.Thus, absent development of reserves or acquisition of properties that have existing proved developed reserves, our revenue could decline as reserves are produced.Our future oil and gas production is, therefore, highly dependent on our level of success in finding or acquiring additional reserves.Our reduced drilling program for 2019 could negatively affect our ability to replace reserves and maintain our current production levels, which could have a material adverse effect on us. Additionally, to the extent our operating cash flow falls below projections and external sources of capital become limited or unavailable, our ability to conduct the capital investment to maintain or expand our asset base would be impaired.

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We recognized material impairments to our Upstream and Midstream assets during 2018. Lower oil, gas and NGL prices or adverse changes in our own operational performance may trigger additional impairments which could have a material adverse effect on us.

We may recognize further significant impairments of our proved and unproved oil and gas properties or other long-lived assets as a result of lower forecasted commodity prices, results of our development activities, reductions to our drilling plans or other material issues related to our businesses. As a result, we may be forced to write-down or write-off assets, restructure our operations, or incur impairment or other charges that could result in accounting losses. Even though these charges may be non-cash items and may not have an immediate impact on our liquidity, the fact that we report charges of this nature could lead to negative market perceptions about us or our securities. In addition, charges of this nature may result in our inability to obtain future financing on favorable terms, or at all.

GAAP requires that we periodically review the carrying value of our properties and other long-lived assets for possible impairment. Based on prevailing commodity prices and specific market factors and circumstances at the time of prospective impairment reviews, and the continuing evaluation of development plans, production data, economics, and other factors, we may be required to impair our assets further.

Our estimated proved reserves and future production rates are based on many assumptions that may prove to be inaccurate.Any material inaccuracies in these reserve estimates or the underlying assumptions will materially affect the quantities and present value of our reserves.

Numerous uncertainties are inherent in estimating quantities of oil and gas reserves. Our estimation of proved reserves is complex and requires significant decisions and assumptions in the evaluation of available geological, engineering and economic data for each reservoir, and these reports rely upon various assumptions, including assumptions regarding production levels and operating and development costs.Although the SEC has established a rule specifying the commodity prices that are incorporated into our proved reserve estimates, the prices that we use in estimating the fair value require us to develop future oil, gas and NGL prices in line with forward market expectations.We also estimate well costs and operating expenses based on recent experience, but these estimates could prove inaccurate. As a result, estimated quantities of proved reserves and projections of future cash flows and production rates and the timing of development expenditures may prove to be inaccurate.Over time, we may make material changes to reserve estimates to reflect actual drilling results and production. Any significant variance in our assumptions and actual results could greatly affect our estimates of reserves, the economically recoverable quantities of oil and gas, the classifications of reserves based on risk of recovery and estimated future net cash flows. Specifically, future prices received for production and costs may vary, perhaps significantly, from the prices and costs assumed for purposes of these estimates. Sustained lower prices will cause the 12-month weighted average price to decrease over time as the lower prices are reflected in the average price, which may result in reductions to the estimated quantities and present values of our reserves.

The standardized measure of our proved reserves will not be the same as the current fair value of our oil and gas properties.

We do not believe that the present value of future net revenue from our proved reserves represents the fair value of our oil and gas properties.In accordance with SEC requirements, we based the estimated discounted future net cash flows from our proved reserves on the 12-month unweighted arithmetic average of the closing prices on the first day of each month for the preceding 12 months without giving effect to derivatives.Actual future net cash flows from our oil and gas properties will be affected by factors such as:

- actual prices we receive for our production, including the effects of our hedging program;
- actual cost of development and production expenses;
- the amount and timing of actual production;
- transportation and processing cost and availability; and
- changes in governmental regulations or taxation.

The timing of both our production and our incurrence of expenses in connection with our operations will affect the timing and amount of actual future net revenue and thus our oil and gas properties' actual present value. In addition, the 10% discount factor we use in the standardized measure may not be the most appropriate discount factor to utilize in determining the fair value of our oil and gas properties.Actual future prices and costs may also differ materially from those used in the present value estimate.

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The requirements of being a public company, including compliance with the reporting requirements of the Exchange Act and the requirements of the Sarbanes-Oxley Act and the NASDAQ, may strain our resources, increase our costs and divert management's attention, and we may be unable to comply with these requirements in a timely or cost-effective manner.

As a public company, we incur significant legal, accounting and other expenses that we would not incur as a private company.We also incur costs associated with our public company reporting requirements and with corporate governance requirements, including requirements under the Sarbanes-Oxley Act, as well as rules implemented by the SEC and the Financial Industry Regulatory Authority.These rules and regulations increase our legal and financial compliance costs and make some activities more time-consuming and costly.These rules and regulations make it more difficult and more expensive for us to obtain director and officer liability insurance and we may be required to accept reduced policy limits and coverage or incur substantially higher costs to obtain the same or similar coverage.As a result, it may be more difficult for us to attract and retain qualified individuals to serve on our Board or as executive officers.

Commencing December 31, 2018, we became a "large accelerated filer" and, accordingly, no longer qualify as an emerging growth company and are no longer able to rely on certain exemptions that were available to us as an emerging growth company. Legal, accounting, administrative and other costs and expenses may increase in the future as we continue to incur both increased external audit fees as well as additional spending to ensure continued regulatory compliance.

We rely on drilling to increase our levels of production. Our production levels will be adversely affected by the planned reductions in our capital program.

A key component to our business strategy is to increase production levels by drilling wells.Although we were successful in elevating production levels during 2018, we cannot provide assurance that we will be able to maintain or grow production levels in the future.For example, our reduced drilling program for 2019 and our limited capital availability could negatively affect our ability to maintain or increase production levels and we are currently estimating a decline in production for each quarter in 2019.We may be unable to accelerate our drilling program in future years to make up for lost production which could have a material adverse effect on us.

We may be unable to make attractive acquisitions or successfully integrate acquired businesses, and any inability to do so may disrupt our business and hinder our ability to grow. Acquisitions that we do complete could be on terms that prove to be uneconomic.

We have made and expect to make future acquisitions of businesses or properties that complement or expand our current business.We may not be able to identify attractive acquisition opportunities. Even if we do identify attractive acquisition opportunities, we may not be able to complete the acquisition or do so on commercially acceptable terms. We may not be able to obtain contractual indemnities from sellers for liabilities incurred prior to our acquisition.

The success of any completed acquisition will depend on our ability to integrate the acquired business into our existing operations.The process of integrating acquired businesses may involve unforeseen difficulties and may require a disproportionate amount of our managerial and financial resources. Our failure to achieve consolidation savings, to integrate the acquired businesses and assets or to minimize any unforeseen operational difficulties could have a material adverse effect on us.

In addition, our debt agreements impose certain limitations on our ability to enter into mergers or combinations transactions and our ability to incur certain indebtedness, which could indirectly limit our ability to engage in acquisitions.

Our business is subject to operational risks that will not be fully insured, which could adversely affect us.

Our business activities are subject to operational risks, including:

- damages or disruptions caused by natural disasters such as earthquakes and adverse weather conditions;
- facility or equipment malfunctions;
- pipeline or tank ruptures or spills;
- surface fluid spills and water contamination;
- fires, blowouts, well collapses and explosions; and
- uncontrollable flows of oil or gas or other well fluids.

In addition, a portion of our gas production is processed to separate NGLs.If the processing plants that service us were to cease operations, we would need to arrange for alternative transportation and processing facilities, which may not be available.If unavailable, we might have to shut in our gas and, therefore, other production, which could reduce our operating cash flow.Further, any alternative facilities could be more expensive than the facilities we currently use.

Any of these types of events could adversely affect our ability to conduct operations or cause substantial losses, including personal injury or loss of life, damage to or destruction of property, natural resources and equipment, pollution or other environmental contamination, loss of wells, regulatory penalties, suspension or termination of operations and attorney's fees and other expenses incurred in the prosecution or defense of litigation.

As is customary in our industry, we maintain insurance against some, but not all, of these risks.Additionally, we may elect not to obtain insurance if we believe that the cost of insurance exceeds our perceived risks. Losses could occur for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. The occurrence of an event that is not fully covered by insurance could have a material adverse impact on us.

Drilling for and producing oil and gas are high risk activities with many uncertainties that could adversely affect us.

Our future financial condition and results of operations will depend on the success of our development, acquisition and production activities, which are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable oil and gas production.

Our decisions to develop or purchase properties will depend on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations.As addressed elsewhere in our Risk Factors, this variability in interpretations presents risk for us.Further, many factors may curtail, delay or cancel our contemplated capital activities, including:

- delays imposed by regulatory bodies or from regulatory compliance, including regulations imposed on produced water disposal;
- regulation limiting the emission of GHGs;
- well set-back legislation or regulation;
- regulation limiting hydraulic fracturing;
- unexpected pressure or irregularities in geological formations;
- shortages of or delays in obtaining equipment, qualified personnel or water for hydraulic fracturing;
- equipment failures, accidents or other unexpected operational events;
- lack of available gathering facilities or delays in construction of gathering facilities;
- lack of available capacity on interconnecting transmission pipelines;
- adverse weather conditions;
- issues related to compliance with environmental regulations;
- environmental hazards, such as leaks, spills, ruptures and unauthorized discharges of fluids and gases associated with our operations;
- declines in oil and gas prices;
- limited availability of financing at acceptable terms; and
- title problems.

Our derivative program could result in financial losses or could reduce our net income.

To achieve more predictable cash flows and to reduce our exposure to fluctuations in the prices of oil and gas, we regularly enter into derivatives ("hedges") covering a significant portion of our expected production. The Alta Mesa RBL requires us to hedge at least 50% of anticipated equivalent production of our PDP reserves for the upcoming twenty-four month period at each measurement date, but also imposes maximum hedging levels for each production stream. Details of our derivative assets are included in Item 8. If we experience a sustained material interruption in our production, we might be forced to make payments under our hedging program without the benefit of the proceeds from our sale of the underlying production, which would have a material adverse effect on us. Further, risk exists that the counterparty in any derivative transaction cannot or will not perform under the instrument and that we will not realize the benefit of the hedge, although all of the counterparties to our current portfolio are lenders under the Alta Mesa RBL. Under that agreement, if a counterparty is a lender and does not perform, then the non-performance is treated as a reduction to the borrowings outstanding. Furthermore, given our current financial condition,

our counterparties have ceased providing the credit necessary to enter into new hedges. Therefore, we may be more exposed to future price fluctuations. We may also be unable to comply with the minimum hedging requirements under the Alta Mesa RBL.

Our policy has been to meet the minimum required hedging levels under the Alta Mesa RBL and to opportunistically hedge an additional portion of our near-term estimated production. Other than the compliance with minimum and maximum hedging levels, our price hedging strategy and future hedging transactions will be determined using Board and management discretion, depending on the financial and future commodity expectations at the time. The prices at which we hedge our production in the future will be dependent upon commodities prices at the time we enter into these transactions, which may be substantially higher or lower than current prices. Accordingly, our price hedging strategy may not protect us from significant declines in prices received for our future production. Conversely, our hedging strategy may limit our ability to realize cash flows from commodity price increases. It is also possible that a substantially larger percentage of our future production will not be hedged, as compared to current or historic levels, which would result in our oil and gas revenue becoming more sensitive to commodity price fluctuations.

Our use of seismic data is subject to interpretation and may not accurately identify the presence of hydrocarbons, which could adversely affect us.

Even when properly used and interpreted, 2-D and 3-D seismic data and visualization techniques help geoscientists in identifying subsurface structures and hydrocarbon indicators, but do not prove the amount, if any, of hydrocarbons present in those structures. The use of seismic data and other advanced technologies requires greater pre-drilling expenditures than traditional drilling strategies, which may result in additional costs without an uplift to a well's economics. As a result, even our successful drilling activities may not prove economic.

We often gather seismic data surveys over large areas including areas where we own no mineral rights. We may choose not to acquire or pursue mineral interests in areas covered by these surveys, which could result in substantial expenditures to acquire and analyze seismic data without the prospect of future benefit of production.

Competition in our industry is intense, making it more difficult for us to acquire properties, market oil or gas and secure trained personnel.

Our ability to acquire additional properties and pursue our operational objectives is dependent upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive market. Our competitors may be able to pay more for oil and gas properties and pursue a greater number of properties than we can. In addition, our industry has periodically experienced shortages of drilling rigs, equipment, pipe and personnel, which has adversely affected the timing and cost of operating. Competition has been historically strong in hiring experienced personnel, particularly in the engineering and technical, accounting, legal and land disciplines. An inability to compete effectively with our competitors could have a material adverse impact on us.

We may not be able to keep pace with technological developments in our industry.

Our industry has been characterized by rapid and significant technological advancements and introductions of new products and services using new technologies, all of which could either generate better recoveries or reduce development costs. As others use or develop new technologies, we may be placed at a competitive disadvantage or competitive pressures may force us to implement those new technologies at substantial costs. In addition, other oil and gas companies may be better able to leverage technological advantages. We may not be able to respond to these competitive pressures and implement new technologies on a timely basis or at an acceptable cost. If one or more of the technologies we use now or in the future were to become obsolete or if we are unable to use the most advanced commercially available technology, it may have a material adverse effect on us.

Deficiencies in title to our leased interests could have a material adverse effect on us.

If an examination of the title history of a property reveals that an oil or gas lease or other developed rights has been purchased in error from a person who is not the owner of the mineral interest desired, our interest would substantially decline in value. In such cases, the amount paid for such oil or gas lease or leases or other developed rights would be lost. In acquiring mineral rights, we typically choose not to incur the expense of retaining title attorneys, instead we rely upon the judgment of oil and gas lease brokers or landmen who perform the fieldwork in examining records before we attempt to acquire a lease or other mineral interest.

Prior to drilling a well that we operate, however, we do obtain a preliminary title review of the spacing unit to ensure there are no obvious defects in title to the well. If we do find defects, we must perform or fund curative work to correct deficiencies in the marketability of the title, such as obtaining affidavits of heirship or causing an estate to be administered. We may also elect to proceed with a well despite defects to the title identified in the preliminary title opinion. If we fail to obtain defensible title to our leasehold, we may be unable to develop additional reserves or benefit from the expected ownership.

Our operations are substantially dependent on the availability of water and our inability to obtain water may have a material adverse effect on us.

Water is an essential component of unconventional oil and gas upstream development during both the drilling and hydraulic fracturing processes. Historically, we have been able to purchase water from local land owners and other sources for use in our operations.However, our access to such water supplies may become limited by factors such as extended drought, competition for water or governmental regulation.If we are unable to obtain sufficient amounts of water, our ability to develop our reserves could be restricted or made less economic, which could have a material adverse effect on us.

Litigation and investigations by private plaintiffs or government officials or entities could adversely affect our performance.

Oil and gas upstream and midstream activities are complex and involve risks that could lead to legal proceedings.We currently are defending litigation and anticipate that we will be required to defend new litigation in the future. The subject matter of such litigation may include releases of hazardous substances from our facilities, contract, title or royalty disputes, regulatory compliance matters, personal injury or property damage matters or disputes related to any other laws or regulations that apply to our operations.In some cases, the plaintiff or plaintiffs seek alleged damages involving large classes of potential litigants and may allege damages relating to extended periods of time or other alleged facts and circumstances. For instance, we and certain of our former and current directors and officers were named as defendants in three putative securities class action claims alleging that the defendants disseminated a false and misleading proxy statement in connection with the Business Combination as well as alleged misstatements after the Business Combination. In addition, the SEC is conducting a formal investigation into the facts involved in the material weakness in our internal controls over financial reporting and the impairment disclosed previously and in this Annual Report.

These and other legal proceedings are inherently uncertain and their results cannot be predicted. Regardless of the outcome, such proceedings could have an adverse impact on us because of legal costs, diversion of management and other personnel and other factors. In addition, it is possible that such proceedings could result in liability, penalties or sanctions, judgments, consent decrees, injunctive relief or orders requiring a change in our business practices, which could have a material adverse effect on us. Accruals for such liabilities, penalties or sanctions may be insufficient, and judgments and estimates to determine accruals or range of losses related to legal and other proceedings could change from one period to the next, and such changes could be material.

Our operations are regulated and the costs to comply or a failure to comply could be costly and have a material adverse effect on us.

We may incur significant costs and liabilities as a result of wide-ranging environmental requirements applicable to our operations. Such environmental laws and regulations include the following federal laws (along with their state counterparts):

- the Clean Air Act (“CAA”), which restricts the emission of air pollutants from many sources, imposes various pre-construction, monitoring and reporting requirements and is relied upon by the U.S. Environmental Protection Agency (“EPA”) as authority for adopting climate change regulatory initiatives relating to GHG emissions;
- the Federal Water Pollution Control Act, also known as the Clean Water Act (“CWA”), which regulates discharges of pollutants from facilities to state and federal waters and establishes the extent to which waterways are subject to federal jurisdiction and rulemaking as protected waters of the United States;
- the Oil Pollution Act (“OPA”), which imposes liabilities for removal costs and damages arising from an oil spill into waters of the United States;
- the Safe Drinking Water Act (“SDWA”), which ensures the quality of the nations’ public drinking water through adoption of drinking water standards and control over the subsurface injection of fluids into belowground formations;
- the Resource Conservation and Recovery Act (“RCRA”), which imposes requirements for the generation, treatment, storage, transport disposal and cleanup of non-hazardous and hazardous wastes;
- the Comprehensive Environmental Response, Compensation, and Liability Act (“CERCLA”), which imposes liability on generators, transporters and arrangers of hazardous substances sent for disposal to sites where hazardous substance

releases have occurred or are threatening to occur, as well as imposes liability on present and certain past owners and operators of sites where hazardous substance releases have occurred or are threatening to occur;

- the Emergency Planning and Community Right to Know Act, which requires facilities to implement a safety hazard communication program and disseminate information to employees, local emergency planning committees and response departments about toxic chemical uses and inventories;
- the Endangered Species Act ("ESA"), which restricts activities that may affect federally identified endangered and threatened species or their habitats through the implementation of operating limitations or restrictions or a temporary, seasonal or permanent ban on operations in affected areas; and
- the National Environmental Policy Act ("NEPA"), which requires federal agencies to evaluate major agency actions having the potential to impact the environment and that may require the preparation of environmental assessments or environmental impact statements.

These U.S. laws and their implementing regulations, as well as state counterparts, generally restrict the level of pollutants emitted to ambient air, discharges to surface water, and disposals or other releases to surface and below-ground soils and ground water. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil and criminal penalties, the imposition of investigatory, remedial and corrective actions, the incurrence of capital expenditures, delays in the permitting, development or expansion of projects, and the issuance of orders enjoining some or all of our future operations in a particular area. Certain environmental laws and regulations impose strict joint and several liability, without regard to fault or legality of conduct, for costs required to clean up and restore sites where hazardous substances or other wastes have been disposed of or otherwise released. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances, wastes or other materials into the environment. The trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment and more stringent laws and regulations may be adopted in the future. Historically, our environmental compliance costs have not had a material adverse effect on our results of operations; however, there can be no assurance that such costs will not be material in the future or that such future compliance will not have a material adverse effect on our business and operating results.

Changes in the legal and regulatory environment governing our industry, particularly changes in the Oklahoma forced pooling system, could have a material adverse effect on us.

Our business is subject to various forms of extensive government regulation, including laws and regulations concerning the location, spacing and permitting of the wells we drill and the disposal of produced water. Changes in the legal and regulatory environment, particularly any changes to Oklahoma's forced pooling procedures could result in increased compliance costs and adversely affect us.

In the past we have used, and we expect to continue to use, Oklahoma's forced pooling process to increase our working interest in sections we propose to drill. In recent years, a relatively low percentage of working interest owners in our operated sections have elected to participate in our wells. Due to the continuing consolidation in the STACK by producers with greater access to capital, other working interest owners may be more likely to participate in the wells we drill. Thus, our ability to use forced pooling to increase our working interest may be more difficult to accomplish.

The adoption of derivatives legislation and regulations could have an adverse impact on our ability to hedge risks associated with our business.

Title VII of the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act") establishes federal oversight and regulation of over-the-counter ("OTC") derivatives and requires the SEC and the Commodity Futures Trading Commission (the "CFTC") to enact further regulations affecting derivatives, including those we use to hedge our commodity exposure. Although the CFTC and the SEC have issued final regulations in certain areas, final rules in other areas and the scope of relevant definitions and/or exemptions still remain to be finalized.

In one of its rulemaking proceedings still pending under the Dodd-Frank Act, the CFTC issued on December 5, 2016 a re-proposed rule imposing position limits for certain futures and option contracts in various commodities (including gas) and for swaps that are their economic equivalents. Under the proposed rules on position limits, certain types of hedging transactions are exempt from these limits on the size of positions that may be held, provided that such hedging transactions satisfy the CFTC's requirements for certain enumerated "bona fide hedging" transactions or positions. A final rule has not yet been issued.

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Similarly, on December 2, 2016, the CFTC re-issued a proposed rule regarding the capital a swap dealer or major swap participant is required to set aside with respect to its swap business, but the CFTC has not yet issued a final rule.

The CFTC issued a final rule on margin requirements for uncleared swap transactions on January 6, 2016, which includes an exemption from any requirement to post margin to secure uncleared swap transactions entered into by commercial end-users in order to hedge commercial risks affecting their business. In addition, the CFTC has issued a final rule authorizing an exemption from the otherwise applicable mandatory obligation to clear certain types of swap transactions through a derivatives clearing organization and to trade such swaps on a regulated exchange, which exemption applies to swap transactions entered into by commercial end-users in order to hedge commercial risks affecting their business.The mandatory clearing requirement currently applies only to certain interest rate swaps and credit default swaps, but the CFTC could act to impose mandatory clearing requirements for other types of swap transactions. The Dodd-Frank Act also imposes record keeping and reporting obligations on counterparties to swap transactions and other regulatory compliance obligations.

All of the above regulations could increase the costs to us of entering into derivatives to hedge or mitigate our commodity price exposure.While we cannot predict when the CFTC will issue final rules applicable to position limits or capital requirements, it may require time and effort for us to comply with position limits and with certain clearing and trade-execution requirements in connection with our derivative activities.When a final rule on capital requirements for swap dealers is issued, the Dodd-Frank Act may require our counterparties to post additional capital, which could increase the costs of future derivatives. In addition, other provisions of the Dodd-Frank Act could cause current counterparties to restructure their derivative activities, including the potential that they might cease engaging in the business of commodity derivatives.

If we voluntarily or involuntarily reduce our use of derivative contracts as a result of the new requirements, we become more exposed to commodity price fluctuations, which could adversely affect our ability to conduct our operations.

We are subject to complex federal, state, local and other laws and regulations that could adversely affect the cost, manner or feasibility of conducting our operations.

Our Upstream operations are subject to complex and stringent laws and regulations. In order to conduct our operations in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals and certificates from various federal, state and local governmental authorities. Failure or delay in obtaining regulatory approvals or drilling permits could have a material adverse effect on our ability to develop our properties, and receipt of drilling permits with onerous conditions could increase our compliance costs. In addition, regulations regarding conservation practices and the protection of correlative rights affect our operations by limiting the quantity of oil and gas we may produce and sell.

We are subject to federal, state and local laws and regulations as interpreted and enforced by governmental authorities possessing jurisdiction over various aspects of the exploration, production and transportation of oil and gas, and incur costs to comply with such federal, state and local laws and regulations.

Under the Natural Gas Act ("NGA"), the Federal Energy Regulatory Commission ("FERC") regulates the interstate transportation and sale for resale of gas, as well as the construction and operation of interstate gas pipelines. As a general matter, states regulate the intrastate transportation, local distribution and retail sale of gas under state laws and regulations.

Under the Interstate Commerce Act ("ICA"), FERC also regulates the rates and practices of oil pipeline companies engaged in interstate transportation, establishes equal service conditions to provide shippers with equal access to oil pipeline transportation, and establishes reasonable rates for transporting petroleum and petroleum products by pipeline.

The U.S. Congress, FERC, state legislatures and regulatory commissions and courts often consider legislative and regulatory proposals and proceedings that could affect the gas and oil industry. The industry historically has been heavily regulated and we cannot predict future legislative and regulatory proposals and proceedings or what effect such proposals or proceedings may have on our operations. The possibility exists that new laws, regulations or enforcement policies could be more stringent and significantly increase our compliance costs. If we are not able to recover the resulting costs through insurance or increased revenue, our financial condition would be adversely affected.

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and gas, technological advances in fuel economy and energy generation devices could reduce demand for oil and gas. The impact of the changing demand for oil and gas may have a material adverse effect on our business, financial condition, results of operations and cash flows.

Should we fail to comply with all applicable statutes, rules, regulations and orders administered by the FERC or CFTC, we could be subject to substantial penalties and fines.

Under the Energy Policy Act of 2005 (“EPAct”), FERC has civil penalty authority under the NGA, including the ability to impose penalties of up to $1 million per day for each violation and disgorgement of profits associated with any violation of the NGA or FERC’s regulations under the NGA. We do not currently operate any FERC-regulated assets nor are we or our subsidiaries regulated by FERC as "natural gas companies" under the NGA. However, as a customer of gas transportation service, we must comply with the terms and conditions of FERC-jurisdictional tariffs pursuant to which transportation service is provided and the anti-market manipulation rules enforced by FERC under the NGA. If we fail to comply with all the applicable FERC-administered statues, rules, regulations and orders, we could be subject to substantial penalties. FERC also has the power to order disgorgement of profits from transactions deemed to violate the NGA.

Under the Commodity Exchange Act (as amended by the Dodd-Frank Act) and regulations promulgated thereunder by the CFTC, the CFTC has also adopted anti-market manipulation, fraud and market disruption rules relating to the prices of commodities, futures contracts, options on futures, and swaps. Additional rules and legislation pertaining to those and other matters may be considered or adopted by Congress, FERC, or the CFTC from time to time. Failure to comply with those statutes, regulations, rules and orders could subject us to civil penalty liability.

Climate change legislation or other regulatory initiatives restricting emissions of GHGs could result in increased operating costs and reduced demand for the oil and gas we produce.

Climate change continues to attract considerable public and scientific attention. As a result, numerous proposals have been made and may continue to be made at the international, national, regional and state levels of government to monitor and limit emissions of GHGs. These efforts have included consideration of cap-and-trade programs, carbon taxes, GHG reporting and tracking programs and regulations that directly limit GHG emissions from certain sources. At the federal level, no comprehensive climate change legislation has been implemented to date. The EPA has, however, adopted regulations under the CAA that, among other things, establish PSD construction and Title V operating permit reviews for GHG emissions from certain large stationary sources that are already potential sources of significant pollutant emissions. Sources subject to these permitting requirements must meet “best available control technology” standards for those GHG emissions. Additionally, the EPA has adopted rules requiring the monitoring and annual reporting of GHG emissions from specified GHG emission sources in the United States, including, among others, onshore and offshore oil and gas production, processing, transmission, storage and distribution facilities, which include certain of our operations.

Federal agencies also directly regulate emissions of methane, a GHG, from oil and gas operations. In August 2016, the EPA issued a final NSPS rule, known as Subpart OOOOa, that requires certain new, modified or reconstructed facilities in the oil and gas sector to reduce these methane gas and volatile organic compound emissions. These Subpart OOOOa standards expand previously issued NSPS published by the EPA in 2012 and known as Subpart OOOO, by using certain equipment-specific emissions control practices. On September 11, 2018, however, the EPA proposed changes to the August 2016 final NSPS rule applicable to oil and gas well vapor leaks. These changes, if implemented, would ease compliance obligations by decreasing fugitive emission monitoring frequency requirements, allowing more time for repairs, and allowing compliance with certain state regulations in lieu of complying with federal regulations. Moreover, on March 2, 2017 the EPA withdrew a previously issued Information Collection Request that sought information about methane emissions from facilities and operations in the oil and gas industry.

In December 2015, the United States attended the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change in Paris, France. At the Conference, an agreement was prepared that requires member countries to determine, plan, and regularly report on their contribution to the mitigation of global warming. Under the agreement, GHG emission reduction goals are established every five years beginning in 2020. The agreement does not create any binding obligations for countries to limit their GHG emissions but, rather, includes pledges to voluntarily limit or reduce future emissions. This “Paris Agreement” was signed by the United States in April 2016 and entered into force in November 2016. On June 1, 2017, President Trump announced that the United States planned to withdraw from the Paris Agreement and to seek negotiations either to reenter the Paris Agreement on different terms or establish a new framework agreement. The Paris Agreement provides for a four-year exit process beginning in November 2016, which would result in an effective exit date of November 2020. The United States’ adherence to the exit process is uncertain, and the terms on which the United States may reenter the Paris Agreement or a separately negotiated agreement, if it chooses to do so, are unclear at this time.

The adoption and implementation of any international treaty, or federal or state legislation, regulations or other regulatory initiative that imposes a carbon tax, requires reporting of GHGs or otherwise restricts emissions of GHGs from our equipment and operations could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, acquire emissions allowances or comply with new regulatory or reporting requirements, that could have an adverse effect on our business, financial condition and results of operations. Moreover, any such new treaty, legislation, regulation or initiative could increase the cost to the consumer, and thereby reduce demand for oil and gas, which could reduce the demand for the oil and gas we produce and lower the value of our reserves.

Finally, it should be noted that some sources estimate that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events. If such effects were to occur, our development and production operations could be adversely affected. Potential adverse effects could include damages to our facilities from powerful winds or rising waters in low lying areas, disruption of our production activities because of climate related damages to our facilities, less efficient or non-routine operating practices necessitated by such climate effects, or increased costs for insurance coverage in the aftermath of such effects. Significant physical effects of climate change could also have an indirect effect on our financing and operations by disrupting the transportation or process-related services provided by midstream companies, service companies or suppliers with whom we have a business relationship. At this time, we have not developed a comprehensive plan to address the legal, economic, social or physical impacts of climate change on our operations. Nor, are we (on our own) capable of doing this in a prudent and accurate manner that would best serve our investors' interests. A number of investors have decided not to invest in hydrocarbon producers, which could have an adverse effect on our future cost of capital.

Federal, state and local legislation and regulatory initiatives relating to hydraulic fracturing could increase our costs of doing business, impose additional operating restrictions or delays and adversely affect our production.

Hydraulic fracturing is an essential and common practice we use to develop our reserves.The process involves the injection of water, sand and additives under pressure into a targeted subsurface formation to fracture the surrounding rock and stimulate production.We routinely apply hydraulic fracturing techniques to stimulate production from the wells we drill.

Our hydraulic fracturing technique is currently generally exempt from regulation under the SDWA's Underground Injection Control ("UIC") program and is typically regulated by the Oklahoma Corporation Commission. However, several federal agencies have asserted regulatory authority or pursued investigations over certain aspects of the process. For example, in December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources, concluding that "water cycle" activities associated with hydraulic fracturing may impact drinking water resources "under some circumstances," including water withdrawals for fracturing in times or areas of low water availability; surface spills during the management of fracturing fluids, chemicals or produced water; injection of fracturing fluids into wells with inadequate mechanical integrity; injection of fracturing fluids directly into groundwater resources; discharge of inadequately treated fracturing wastewater to surface waters; and disposal or storage of fracturing wastewater in unlined pits. In June 2016, the EPA published an effluent limit guideline final rule prohibiting the discharge of wastewater from onshore unconventional oil and gas extraction facilities to publicly owned wastewater treatment plants and, in 2014, the EPA asserted regulatory authority pursuant to the UIC program over hydraulic fracturing activities involving the use of diesel and issued guidance covering such activities. Also, in 2015, the Bureau of Land Management ("BLM") published a final rule that established new or more stringent standards relating to hydraulic fracturing on federal and American Indian lands. On December 29, 2017, BLM rescinded the 2015 rule. California and certain environmental groups have sued over the BLM's rescission of the 2015 rule.

Additionally, in 2014, the EPA published an advanced notice of public rule making regarding Toxic Substances Control Act ("TSCA") reporting of the chemical substances and mixture used in hydraulic fracturing. From time to time, Congress has introduced, but not adopted, legislation to provide for federal regulation of hydraulic fracturing and to require disclosure of chemicals used in the fracturing process.

In addition, some states, including Oklahoma, have adopted, regulations that restrict or could restrict hydraulic fracturing in certain circumstances and that require the disclosure of the chemicals used in hydraulic fracturing operations. Concerns have been raised that hydraulic fracturing activities may be correlated to anomalous seismic events. In December 2016, the OCC Oil and Gas Conservation Division and the Oklahoma Geological Survey released well completion seismicity guidance, which requires operators to take certain prescriptive actions, including an operator's planned mitigation practices, following certain unusual seismic activity within 1.25 miles of hydraulic fracturing operations. States could elect to prohibit high-volume hydraulic fracturing altogether, following the approach taken by the State of New York in 2015. In addition to state laws, local land use restrictions, such as city ordinances, may restrict drilling in general and/or hydraulic fracturing in particular, although

Oklahoma has taken steps to limit the authority of local governments to regulate oil and gas development. The issuance of any laws, regulations or other regulatory initiatives that impose new obligations on, or significantly restrict hydraulic fracturing, could make it more difficult or costly for us to develop our reserves or conduct our operations, either one of which could have a material adverse effect on us.

Legislation or regulatory initiatives intended to address seismic activity could restrict our ability to dispose of produced water gathered from our drilling and production activities, which could have a material adverse effect on our business.

We dispose of produced water gathered from our operations pursuant to permits issued to our affiliates or third-party vendors by governmental authorities overseeing such disposal activities. While these permits are issued pursuant to existing laws and regulations, these legal requirements are subject to change, which could result in the imposition of more stringent permitting or operating constraints or new monitoring and reporting requirements owing to, among other things, concerns of the public or governmental authorities regarding such disposal activities.

One such concern relates to recent seismic events near underground injection wells used for the disposal of produced water resulting from oil and gas activities. When caused by human activity, such events are called induced seismicity. Developing research suggests that the link between seismic activity and wastewater disposal may vary by region, and that only a very small fraction of the tens of thousands of injection wells have been suspected to be, or have been, the likely cause of induced seismicity. In March 2016, the United States Geological Survey identified six states with the most significant hazards from induced seismicity, including Oklahoma, where we operate. In response to these concerns regarding induced seismicity, regulators in some states, including Oklahoma, have imposed, and other states are considering imposing, additional requirements in the permitting of produced water injection wells or otherwise to assess any relationship between seismicity and the use of such wells. For example, Oklahoma issued new rules for injection wells in 2014 that imposed certain permitting and operating restrictions and reporting requirements on injection wells in proximity to faults and also, from time to time, developed and implemented plans directing certain wells where seismic incidents have occurred to restrict or suspend injection well operations. The Oklahoma Corporation Commission (“OCC”) has implemented the National Academy of Science’s “traffic light system,” in determining whether new injection wells should be permitted, permitted only with special restrictions, or not permitted at all. In addition, the OCC has established rules requiring operators of certain produced water injection wells in seismically-active areas, or Areas of Interest, within the Arbuckle formation of the state to, among other things, conduct mechanical integrity testing or make certain demonstrations of such wells’ depth that, depending on the depth, could require the plugging back of such wells and/or the reduction of volumes disposed in such wells. As a result of these measures, the OCC from time to time has developed and implemented plans calling for injection wells within Areas of Interest where seismic incidents have occurred to restrict or suspend disposal operations in an attempt to mitigate the occurrence of such incidents. In February 2017, the OCC’s Oil and Gas Conservation District issued an order limiting future increases in the volume of oil and gas wastewater injected below ground into the Arbuckle formation in an effort to reduce the number of earthquakes in the state.

Also, ongoing lawsuits allege that injection well disposal operations have caused damage to neighboring properties or otherwise violated state and federal rules governing waste disposal. These developments could result in additional regulation and restrictions on the use of injection wells. Increased regulation and attention given to induced seismicity could lead to greater opposition, including litigation, to oil and gas activities utilizing injection wells for produced water disposal. Evaluation of seismic incidents and whether or to what extent those events are induced by the injection of produced water into disposal wells continues to evolve, as governmental authorities consider new and/or past seismic incidents in areas where produced water injection activities occur or are proposed to be performed. Court decisions or the adoption of any new laws, regulations or directives that restrict our ability to dispose of produced water generated by production and development activities, whether by plugging back the depths of disposal wells, reducing the volume of produced water disposed in such wells, restricting injection well locations or otherwise or by requiring us to shut down injection wells, could significantly increase our costs to manage and dispose of this produced water, which could have a material adverse effect on our financial condition and results of operations.

Laws and regulations pertaining to threatened and endangered species or protective of environmentally sensitive areas could delay or restrict our operations and cause us to incur significant costs.

Our operations may be adversely affected by seasonal or permanent restrictions or costly mitigation measures imposed under various federal and state statutes in order to protect endangered or threatened species and their habitats, migratory birds, wetlands and natural resources. Federal statutes, as amended from time to time, that are protective of these species, birds and environmentally sensitive areas include the ESA, the Migratory Bird Treaty Act (the “MBTA”), the CWA, the CERCLA and the OPA. For example, to the extent that species are listed under the ESA or similar state laws and live in areas where our oil and gas upstream activities are conducted, our ability to conduct or expand operations and construct facilities could be limited or we

could be forced to incur material additional costs. Moreover, our operations may be delayed, restricted or precluded in protected habitat areas or during certain seasons, such as breeding and nesting seasons.

Additionally, the U.S. Fish and Wildlife Service ("FWS") may designate new or increased critical habitat areas that it believes are necessary for survival of threatened or endangered species, which designation could result in material restrictions to federal land use and private land use and could delay or prohibit land access or oil and gas development. As a result of one or more settlements approved by the federal government, the FWS must make determinations on the listing of numerous specified species as endangered or threatened under the ESA pursuant to specified timelines. The designation of previously unidentified endangered or threatened species could indirectly cause us to incur additional costs, cause our operations to become subject to operating restrictions or bans, and limit future development activity in affected areas. If harm to protected species or damages to wetlands, habitat or natural resources occur or may occur, government entities or, at times, private parties may act to prevent oil and gas exploration or development activities or seek damages for harm to species, habitat or natural resources resulting from drilling or construction or releases of oil, wastes, hazardous substances or other regulated materials, and, in some cases, may seek criminal penalties. The designation of previously unprotected species as threatened or endangered in areas where we conduct operations could cause us to incur increased costs arising from species protection measures or time delays or limitations on our operations.

We could experience periods of higher costs if oil and gas prices rise or as drilling activity otherwise increases in the STACK, which could reduce our ability to develop our reserves and otherwise have a material adverse effect on us.

Historically, our capital and operating costs typically rise during periods of sustained increasing oil, gas and NGL prices. These cost increases result from a variety of factors beyond our control as drilling activity increases, such as increases in the cost of electricity, tubular goods, water, sand and other disposable materials used in fracture stimulation and other raw materials that we and our vendors rely upon; and the cost of services and labor, especially those required in horizontal drilling and completion. As commodity prices rise or drilling activity otherwise increases in the STACK, our costs for materials, services and labor may increase, which may negatively impact our profitability, cash flow and cause us to delay, reduce or curtail our drilling program.

The sale of our production is dependent upon midstream and downstream facilities over which we may have no control

The marketability of our production depends upon the availability, proximity and capacity of facilities and services, including pipelines, natural gas gathering systems, trucking or terminal facilities and processing facilities. We deliver oil, gas and NGLs through gathering systems and pipelines that we do not necessarily own. The lack of available capacity on these systems and facilities could impact us by causing our production to be shut-in, reducing the price we receive for our production or delaying or eliminating our future development plans.Although we have some contractual control over this third-party-operated risk by virtue of the underlying contracts, such systems and facilities may be temporarily unavailable due to market conditions or operational reasons. Further, in the future, these systems and facilities may not be available to us at a price that is acceptable to us. Any significant change in market factors or other conditions affecting these systems and facilities, as well as any delays in constructing new systems and facilities, could have a material adverse effect on us.

Our Upstream business relies primarily on KFM for gathering, transportation, processing and produced water disposal services.

Our oil and gas production, not otherwise previously dedicated, is dedicated to KFM.Also, in November 2018, Alta Mesa sold its produced water assets to a subsidiary of KFM. In conjunction with the sale, Alta Mesa entered into a new 15-year water gathering and disposal agreement with KFM's subsidiary. As a result, our Upstream business is substantially dependent upon KFM for its oil, NGL, gas and produced water-related operations. If KFM were unable to continue to provide these services, it could result in the shut-in of our production or cause delays and additional costs to find alternate providers for those services, any one of which could have a material adverse effect on us.

The parties on whom we rely for gathering, transportation and processing services are subject to complex federal, state and other laws that could adversely affect the cost, manner or feasibility of conducting our business.

Gathering, transportation and processing operations are subject to complex laws and regulations that require parties providing these services to obtain and maintain numerous permits, approvals and certifications with various levels of government. These operations could require substantial costs in order to comply with existing laws and regulations. If laws and regulations governing such operations are enacted, revised or reinterpreted, these changes may affect the costs that we pay for such

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services. There could be a material adverse effect on us if the gathering, transportation and processing operations that we rely upon were materially impacted by those laws and regulations.

We have limited control over activities on properties we do not operate, which could reduce our production and revenue.

We have limited control over properties that we do not operate, including a limited ability to influence normal operating procedures, expenditures or future development of the underlying properties. The failure of another operator to adequately perform operations or that operator's financial difficulties could reduce our production and revenue. The success and timing of our drilling and development activities on properties operated by others, depends upon a number of factors outside of our control, including the operator's timing of development and amount of capital expenditures, expertise and financial resources.

Turnover of our key executives and Board of Directors and difficulty of recruiting and retaining key employees could have a material adverse impact on our business.

We experienced a significant amount of executive-level turnover in late 2018. In early 2019, we introduced a new executive team including an Interim President, an Interim Chief Operating Officer and a Chief Financial Officer.Our inability to retain the new management team and our remaining key executives and employees could harm our business and operations and have a material adverse effect on us.

Our success will depend to a large extent upon the efforts and abilities of our management team and having experienced individuals serving on our Board who are also knowledgeable about our operations and our industry. We may be unable to timely replace the talents and skills of our management team or directors if one or more did not continue serving. Our business also depends upon our ability to attract and retain qualified personnel. If we are unable to retain or find replacement employees, the loss of the services of one or more of these key employees could have a material adverse effect on us. We do not maintain key-man life insurance with respect to any of our employees. Acquiring and keeping personnel could prove more difficult or cost substantially more than estimated. These factors could cause us to incur greater costs or prevent us from pursuing our development and exploitation strategy as quickly as we would otherwise wish to do.

We operate in an area of high industry activity, which may affect our ability to hire, train or retain qualified personnel needed to manage and operate our assets.

Oil and gas development in the STACK has been quite active in recent years. As a result, demand for qualified personnel in this area, and the cost to attract and retain such personnel, increased over the past few years and may increase again in the future. Moreover, our competitors may be able to offer better compensation packages to attract and retain qualified personnel than we are able to offer. Any delay or inability to secure the personnel necessary for us to conduct our planned development activities could result in our production falling below our forecasted volumes, which could have a material adverse effect on us at our estimated production levels in the next several years.

We may encounter obstacles marketing our oil and gas which could adversely impact our revenue.

The marketability of our production will depend in part upon the availability of purchasers in our area plus gathering systems and pipelines owned by third parties. Transportation space on the gathering systems and pipelines we utilize is occasionally limited or unavailable due to repairs or improvements to facilities, but since we hold firm transportation covering our current level of gas production we do not believe a significant risk exists that other companies would hold priority over us in the near term.

The availability of markets is beyond our control. If market factors dramatically change, our revenue could be substantially impacted, which could have a material adverse effect on us.

We have identified material weakness in our internal control over financial reporting which, if not corrected, could affect the reliability of our financial statements, increase our costs and efforts to ensure accurate reporting and have other adverse consequences.

Our management is responsible for establishing and maintaining adequate internal control over financial reporting (ICFR).Section 404 of SOX requires management to assess the effectiveness of our ICFR. Based on our assessment as of December 31, 2018, we concluded that our ICFR was not effective as of that date, due to identification of material weakness. A material weakness is a deficiency or combination of deficiencies in ICFR that causes a reasonable possibility that a material

misstatement could occur and not be prevented or detected on a timely basis. Our material weakness relates to both the design of our controls and execution of control procedures. Item 9A contains additional information regarding our deficiencies and the proposed remediation plan.

If not remediated, the material weaknesses could result in a material misstatement to our annual or interim consolidated financial statements that would not be prevented or detected on a timely basis. Our management has developed, and begun to implement, a plan to remediate the material weaknesses. We may not be able to implement the plan, or to remediate the material weaknesses in a timely manner. In addition, we may require more than one year to effect a system of internal controls and an information technology environment that are sufficiently designed and properly executed to prevent material misstatements from going undetected. Furthermore, during the course of re-designing existing processes and controls, implementing additional processes and controls and testing of the operating effectiveness of such re-designed and additional processes and controls, we may identify additional control deficiencies that could give rise to other material weakness, in addition to the currently identified matters. If we are unable to remediate our material weakness, or if additional material weakness or deficiency is discovered, we may be unable to report our financial results accurately or timely, which could cause our reported financial results to be materially misstated, which could adversely affect the market price of our securities and our ability to access the capital markets. Furthermore, the effort to remediate our internal controls could be expensive or could distract management from managing the business, either of which could adversely affect us.

There are inherent limitations in all control systems, and misstatements due to error or fraud that could seriously harm our business may occur and not be detected.

We do not expect that our internal controls and disclosure controls will prevent all possible error and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. In addition, the design of a control system must reflect the resource constraints and the benefit of controls relative to their costs. Because of the inherent limitations in all control systems, an evaluation of controls can only provide reasonable assurance that all material control issues and instances of fraud, if any, in our Company have been detected. These inherent limitations reflect that judgments in decision-making can be faulty and that breakdowns can occur because of simple error or mistake. Further, controls can be circumvented by the individual acts of some persons or by collusion of two or more persons. The design of any system of controls is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Because of inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected. A failure of our controls and procedures to detect error or fraud could seriously harm our business and results of operations.

Our business and operations could be negatively impacted by shareholder activism, which could cause us to incur significant expense, hinder execution of our business strategy and impact our stock price.

Shareholder activism, which could take many forms and arise in a variety of situations, could result in substantial costs and divert management's and our Board's attention and resources from our business. Additionally, such shareholder activism could give rise to perceived uncertainties as to our future, adversely affect our relationships with service providers and make it more difficult to attract and retain qualified personnel. Also, we may be required to incur significant legal fees and other expenses related to activist shareholder matters. Our stock price could be subject to significant fluctuation or otherwise be adversely affected by the events, risks and uncertainties of any shareholder activism.

Cyber-attacks targeting systems and infrastructure may adversely impact our operations.

Our industry has become increasingly dependent on digital technologies to conduct day-to-day operations. For example, software programs are used to interpret seismic data, manage drilling rigs, production equipment and gathering and transportation systems, conduct reservoir modeling and for compliance reporting. Industrial control systems such as SCADA (supervisory control and data acquisition) now control large scale processes that can include multiple sites and long distances, such as power generation and transmission, communications and oil and gas pipelines.

We depend on digital technology, including information systems and related infrastructure as well as cloud applications and services, to process and record financial and operating data, communicate with our employees and business partners, analyze seismic and drilling information, estimate quantities of oil and gas reserves as well as other activities related to our business. Our business partners, including vendors, service providers, purchasers of our production, and financial institutions, are also

dependent on digital technology. The technologies needed to conduct oil and gas exploration and development activities and global competition for oil and gas resources make certain information the target of theft or misappropriation.

As dependence on digital technologies has increased, cyber incidents, including deliberate attacks or unintentional events, also have increased. A cyber-attack could include gaining unauthorized access to digital systems for purposes of misappropriating assets or sensitive information, corrupting data, or causing operational disruption, or result in denial-of-service on websites. SCADA-based systems are potentially vulnerable to targeted cyber-attacks due to their critical role in operations.

Our systems and networks, and those of our business partners may become the target of cyber-attacks or information security breaches that could result in the unauthorized release, gathering, monitoring, misuse, loss or destruction of information, or cause other disruptions to our business operations. In addition, certain cyber incidents, such as surveillance, may remain undetected for an extended period.

A cyber incident involving our information systems and related infrastructure, or that of our business partners, could disrupt our business plans and negatively impact our operations in the following ways, among others:

- unauthorized access to seismic data, reserves information, royalty owner data or other sensitive or proprietary information could have a negative impact on our ability to compete for oil and gas resources;
- data corruption, communication interruption, or other operational disruption during drilling activities could result in failure to reach the intended target or a drilling incident;
- data corruption or operational disruption of production infrastructure could result in loss of production, or accidental discharge;
- a cyber-attack on a vendor or service provider could result in supply chain disruptions which could delay or halt a development project, effectively delaying the start of cash flows from the project;
- a cyber-attack on a third party gathering or pipeline service provider could prevent us from marketing our production, resulting in a loss of revenue;
- a cyber-attack involving commodities exchanges or financial institutions could slow or halt commodities trading, thus preventing us from marketing our production or engaging in hedging activities, resulting in a loss of revenue;
- a cyber-attack on a communications network or power grid could cause operational disruption resulting in loss of revenue;
- a deliberate corruption of our financial or operational data could result in events of non-compliance which could lead to regulatory fines or penalties; and
- expensive remediation efforts, distraction of management or damage to our reputation.

Our implementation of various controls and processes, including globally incorporating a risk-based cyber security framework, to monitor and mitigate security threats and to increase security for our information, facilities and infrastructure is costly and labor intensive. Moreover, there can be no assurance that such measures will be sufficient to prevent security breaches from occurring. As cyber threats continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any information security vulnerabilities.

Certain U.S. federal income tax preferences could be eliminated as a result of future legislation.

There has been proposed legislation that would, if enacted, make significant changes to U.S. tax laws regarding provisions currently available to oil and gas companies. Such legislative changes have included the elimination of certain key U.S. federal income tax incentives currently available to oil and gas upstream development. If enacted into law, these proposals would eliminate certain tax preferences applicable to taxpayers engaged in our industry. These changes include:

- the repeal of the percentage depletion allowance;
- the elimination of current deductions for intangible drilling costs; and
- the increase in the amortization period from two years to seven years for geophysical costs.

It is unclear whether any such changes will be enacted or proposed by current or future administrations or how soon any such changes would become effective. In addition, Congress passed tax reform in December of 2017, and that legislation has changes including, but not limited to:

- the elimination of the deduction for U.S. production activities;

- the provision for individual taxpayers to deduct 20% of their domestic qualified business income (which may provide some relief from the aforementioned item);
- more stringent limitation on business interest deduction;
- modification of NOL carryforward rules; and
- changes to items excluded from the $1.0 million executive compensation deduction limitation.

The further passage of any legislation, including the proposals above, or changes in U.S. federal income tax laws could negatively affect our financial condition and results of operations.

Risks Related to Our Indebtedness

We have substantial indebtedness and may incur substantially more debt. Higher levels of indebtedness make us more vulnerable to economic downturns and adverse developments in our business.

Our present level of indebtedness requires us to use a substantial portion of our cash flow to pay interest, which reduces funds available to finance our capital and acquisition activities and could limit our flexibility in reacting to changes in our business. The outstanding debt under both the Alta Mesa RBL and KFM Credit Facility bears interest at a variable rate, and so a rise in interest rates will generate greater interest expense (provided we have not hedged against interest rate increases). The amount of our debt may also cause us to be more vulnerable to economic downturns and adverse developments in our business.

We may incur substantially more debt in the future. The indenture governing our outstanding 2024 Notes contains restrictions on our incurrence of additional indebtedness. These restrictions, however, are subject to a number of qualifications and exceptions, and under certain circumstances, we could incur substantial additional indebtedness and remain in compliance with these restrictions. Moreover, these restrictions do not prevent us from incurring obligations that do not constitute "indebtedness" as defined under the indenture.

Our ability to meet our debt obligations and other expenses will depend on our future performance, which will be affected by financial, business, economic, regulatory and other factors, many of which we are unable to control. If cash flow is not sufficient to service debt, we may be required to refinance debt, sell assets or sell additional securities on terms that we may not find attractive if it may be done at all. Further, the failure to comply with the financial and other restrictive covenants relating to the indebtedness could result in a default under that indebtedness, which could have a material adverse affect on us.

Our significant indebtedness could give rise to other material adverse consequences, including the following:

- the Alta Mesa RBL and the indenture governing the 2024 Notes have cross default provisions, which could result in the acceleration of indebtedness under both agreements if we fail to comply with the covenants and other provisions in either agreement;
- it may be difficult to satisfy our obligations, including debt service requirements under debt agreements, or maintain compliance with financial and other debt covenants;
- we might be unable to fund operations, working capital, capital expenditures, debt service requirements and other general corporate needs;
- a significant portion of our cash flow is committed to payments on our debt, which will reduce the funds available to us for other purposes, such as future capital expenditures, acquisitions and general working capital;
- we are more vulnerable to price fluctuations and to economic downturns and adverse industry conditions and our flexibility to plan for, or react to, changes in our business or industry is more limited; and
- our ability to capitalize on business opportunities and to react to competitive pressures may be limited.

The Alta Mesa RBL and the indenture governing Alta Mesa's 2024 Notes have restrictive covenants that could limit its growth, financial flexibility and its ability to engage in certain activities. Since Alta Mesa is our subsidiary, most of the effects apply to us.

The Alta Mesa RBL and the indenture governing Alta Mesa's 2024 Notes have restrictive covenants that could limit our growth, financial flexibility and our ability to engage in activities that may be in our long-term best interests. These covenants, among other things, limit our ability to:

- incur additional indebtedness;
- sell assets;
- guaranty or make loans to others;

- make investments;
- enter into mergers;
- make certain payments and distributions;
- enter into or be party to hedge agreements;
- amend our organizational documents;
- incur liens; and
- engage in certain other transactions without the prior consent of our lenders.

In addition, the Alta Mesa RBL requires Alta Mesa to maintain financial ratios or to reduce its indebtedness if it is unable to comply with such ratios, which may limit its ability to obtain future financings to withstand a future downturn in its business or the economy in general or to otherwise conduct necessary corporate activities. Alta Mesa may also be prevented from taking advantage of business opportunities that arise because of these limitations.

Any significant reduction to the Alta Mesa RBL borrowing base as a result of the periodic redeterminations or other reasons may negatively impact our ability to fund our operations and we may not have sufficient funds to repay borrowings under the Alta Mesa RBL, if required as a result of a borrowing base redetermination.

Availability under the Alta Mesa RBL was subject to a borrowing base of$400.0 million at December 31, 2018. The borrowing base is subject to at least semi-annual redeterminations that are based on the value of Alta Mesa's oil and gas reserves as determined by the Alta Mesa RBL lenders and other factors deemed relevant by the lenders. On April 1, 2019, the borrowing base was reduced to$370.0 million upon completion of the regularly scheduled semi-annual redetermination. Substantially all of the available borrowing base is currently utilized.In August 2019, the lenders exercised their option to conduct an optional redetermination, pursuant to which they established a revised borrowing base of $200.0 million, which will require us to make monthly installments of $32.5 million for five months beginning in September 2019.As a consequence of reduced operating cash flow and a lowered borrowing base, we have limited ability to obtain the capital necessary to conduct our operations at desired levels. Additionally, if we are in default under the Alta Mesa RBL, the lenders could cease making amounts available, accelerate payment of amounts outstanding or seek other remedies any of which would further limit our access to the capital necessary to fund our capital expenditures.Declines in oil and gas prices or a decrease in reserves for any reason, including the removal of our PUDs in April 2019, could cause the Alta Mesa RBL banks to reduce the borrowing base as part of future redeterminations. Any significant future reduction in our borrowing base could have a material negative impact on our liquidity and our ability to fund our operations.Further, if the outstanding borrowings under the Alta Mesa RBL were to exceed the borrowing base due to any such redetermination, we would be required to repay the excess. We may not have sufficient funds to make such repayments. If we do not have sufficient funds and we are otherwise unable to negotiate renewals of our borrowings or arrange new financing, we may be in default under the Alta Mesa RBL, which could have a material adverse effect on us.

If we are unable to comply with the restrictions and covenants in our debt agreements, we could default under the terms of such agreements, which could ultimately result in an acceleration of repayment.

If we cannot comply with the restrictions and covenants in our debt agreements, there could be a default under the terms of these agreements. Our ability to comply with these restrictions and covenants, including meeting financial ratios and tests, may be affected by events beyond our control. As a result, we cannot provide assurance that we will be able to comply with these restrictions and covenants or meet such financial ratios and tests. Although certain types of circumstances (such as delays in providing timely financial information) give rise to defaults that are curable under the agreements, we may not be able to cure all defaults within the cure period, which could give rise to an event of default and potentially an acceleration of amounts due. Moreover, if we are in default on any indebtedness, we would be unable to make borrowings under the Alta Mesa RBL or the KFM Credit Facility even if there are remaining borrowings available thereunder.

If we are unable to generate sufficient cash flow or are otherwise unable meet required payments of principal, premium, if any, and interest on our indebtedness, or if we otherwise fail to comply with the various covenants, including financial and operating covenants in the instruments governing our indebtedness, we could be in default under those agreements. During 2019, we may be unable to satisfy the consolidated total leverage ratio in the Alta Mesa RBL and recognize the need to obtain covenant relief or to replace the Alta Mesa RBL with debt that would allow us to meet any attendant covenant requirements. In the event of such a default, the holders of such indebtedness could elect to declare all the funds borrowed thereunder to be due and payable, the lenders under the Alta Mesa RBL could terminate their commitments to lend, cease making further loans and institute foreclosure proceedings against our assets, and we could be forced into bankruptcy protection. Borrowings under other debt instruments that contain cross-acceleration or cross-default provisions, such as the indenture governing Alta Mesa's 2024 Notes, may also be accelerated and become due and payable. If any of these events occur, our assets might not be sufficient to repay in

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full all of our outstanding indebtedness and we may be unable to find alternative financing. Even if we could obtain alternative financing, it might not be on terms that are favorable or acceptable to us. Additionally, we may not be able to amend our debt agreements or obtain needed waivers on satisfactory terms.

To service our indebtedness, we require significant liquidity and our ability to generate cash depends on many factors beyond our control.

Our ability to service and refinance our debt and to fund planned capital expenditures depends on our generating cash.This ability hinges on general economic, financial, competitive, legislative, regulatory and other factors beyond our control. We can provide no assurance that we will generate sufficient operating cash flow, that we will realize the planned operating cost improvements or that future borrowings will be available to us in an amount sufficient to service and repay our debt, while still funding our other liquidity needs. If we are unable to satisfy our debt obligations, we may have to undertake alternative plans such as:

- refinancing or restructuring our debt;
- selling assets;
- reducing or delaying capital investments; or
- seeking to raise additional capital.

Any alternative plans that we undertake may still not enable us to meet our debt obligations. We can provide no assurance that any refinancing or debt restructuring would be possible, that any assets could be sold or that, if sold, the timing of the sales and proceeds realized from those sales would be favorable or that additional financing could be obtained on acceptable terms. Our inability to generate sufficient cash flows to satisfy our debt or to obtain alternative financing could have a material adverse effect on us and could result in us being unable to continue as a going concern.

Restrictions in KFM's Credit Facility could adversely affect its financial condition, results of operations or cash flows. Since KFM is our subsidiary, most of the effects of these debt facilities on KFM apply equally to us.

KFM is a party to a $300.0 million credit agreement that matures on May 30, 2023, with quarterly interest payments due on Base Rate loans. KFM's interest rates depend upon its consolidated leverage ratio and KFM can elect to borrow on a Eurodollar Loan or Base Rate Loan basis. Both the Eurodollar Loan and Base Rate Loan margins are subject to minimum rates established by third-party institutions, such as, but not limited to the Federal Reserve. The terms of this credit agreement limit KFM's ability to, among other things:

- incur or guarantee additional debt;
- make certain investments and acquisitions;
- incur certain liens or permit them to exist;
- enter into certain types of transactions with affiliates;
- merge or consolidate with another company; and
- transfer, sell or otherwise dispose of assets.

The KFM Credit Facility also contains covenants requiring it to maintain certain financial ratios. KFM's ability to meet those financial ratios and tests can be affected by events beyond its control, and KFM cannot assure that it will meet any such ratios and tests.

The provisions of the KFM Credit Facility may affect its ability to obtain future financing and pursue attractive business opportunities and its flexibility in planning for, and reacting to, changes in business conditions. In addition, a failure to comply with the provisions of the credit facility could result in a default or an event of default that could enable KFM's lenders to declare the outstanding principal of that debt, together with accrued and unpaid interest, to be immediately due and payable. If the payment of KFM's debt is accelerated, its assets may be insufficient to repay such debt in full.

If High Mesa Inc. and its subsidiaries (collectively, "HMI") default on their obligations to us, it could have a material adverse effect on us and our results of operations, and could cause a default under the Alta Mesa RBL and could adversely impact the trading price for our securities.

High Mesa Services LLC ("HMS"), a subsidiary of HMI, is the promissor under two promissory notes in the principal amount of $1.5 million and $8.5 million. As of December 31, 2018, approximately $1.7 million and $11.7 million, respectively, were

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outstanding under the promissory notes including the accumulated interest cost. The promissory notes became the property of the Company pursuant to the identification of acquired assets under the Business Combination. When the $1.5 million promissory note became due on February 28, 2019, HMS made no payment and therefore defaulted under its terms, and HMS has failed to cure such default. Following the default, we submitted a demand letter to preserve our rights, declaring all amounts owing under the $1.5 million note immediately due and payable. HMI disputes that it has any obligation to pay the $1.5 million promissory note and the $8.5 million promissory note to us. We are pursuing remedies in connection with securing repayment of the past due promissory note by HMS and the $8.5 million promissory note, which matures on December 31, 2019, but there is no guarantee that we will be successful in securing such repayment in full, or in part, or that HMI will have the liquidity necessary to repay the notes.

Pursuant to the Business Combination, we distributed our non-STACK oil and gas assets to a subsidiary of HMI, and certain subsidiaries of HMI agreed to indemnify and hold us harmless from any liabilities associated with those non-STACK oil and gas assets, regardless of when those liabilities arose. We also entered into a management services agreement (the "MSA") with HMI whereby we agreed to provide management services to HMI with respect to the non-STACK oil and gas assets, which included both operational and administrative functions. At December 31, 2018, HMI owed us approximately $10.0 million, which includes amounts owed (i) under the MSA, (ii) from a duplicate revenue payment made to HMI and (iii) pursuant to payables arising prior to the Business Combination. Subsequent to year-end, we billed HMI an additional $0.9 million for incremental MSA costs incurred and have received approximately $1.0 million in payments toward all amounts outstanding. HMI has disputed certain of these amounts. We are pursuing remedies under applicable law in connection with repayment of this receivable. There is no guarantee that HMI will pay the amounts it owes. In addition, our ability to collect these amounts or future amounts that may become due pursuant to indemnification obligations may be adversely impacted by liquidity and solvency issues at HMI. As a result, we have recognized an allowance for uncollectible accounts of $9.0 million to fully provide for the un-remitted balance and may have future allowances for amounts incurred in 2019 prior to the termination of the MSA. We also may be subject to liabilities for the non-STACK assets for which we should be indemnified, including liabilities associated with litigation relating to the non-STACK assets.

Under the Alta Mesa RBL, Investments (as defined) are limited to $10.0 million. If the amounts due from HMI continue unpaid, they may be deemed Investments, which when aggregated with other Investments could cause Alta Mesa to be in default under the Alta Mesa RBL. Such default would require us to get a waiver or other relief from our lenders. If we are unable to get such relief, the lenders may exercise their rights under the agreement, which as described elsewhere in our Risk Factors, could include acceleration of amounts due. A failure by HMI to pay its obligations to us could also have an adverse impact on our financial position and results of operations. Alternatively, if HMI, which holds an estimated134.0 million shares of our Class C Common Stock, sells all or a portion of those shares to fulfill its obligations under the MSA, the trading price of our shares may be negatively affected.

Additionally, we are co-guarantors under certain surety bonds with HMI, including bonds that cover the non-STACK oil and gas assets owned by them. The surety has requested posting of collateral. If HMI cannot post collateral or satisfy its indemnity obligations, Alta Mesa may be required to post collateral or otherwise satisfy HMI's obligations associated with HMI surety bonds in an amount of approximately$15 million.

Risks Related to our Midstream Business

We must continually compete for crude oil, gas and produced water supplies, and any decrease in supplies of such commodities could adversely affect our financial condition, results of operations or cash flows.

In order to maintain or increase throughput levels in our gathering system and asset utilization rates at our processing plant, we must continually contract for new product supplies. We may not be able to obtain additional contracts for crude oil and gas and NGL supplies. The primary factors affecting our ability to connect new wells to our gathering facilities include our success in contracting for existing supplies that are not committed to other systems and the level of drilling activity near our gathering system. If we are unable to maintain or increase the volumes on our system by accessing new supplies to offset the natural decline in reserves, our business and financial results could be adversely affected. In addition, our future growth will depend in part upon whether we can contract for additional supplies at a greater rate than the rate of natural decline in our current supplies.

Any decrease in the volumes that we gather, process, store or transport would adversely affect our financial condition, results of operations or cash flows.

Our financial performance depends to a large extent on the volumes of crude oil, gas and produced water gathered, processed, stored and transported on our assets. Decreases in the volumes of crude oil, gas and produced water we gather, process, store or transport would directly and adversely affect our financial condition, results of operations or cash flows. These volumes can be influenced by factors beyond our control, including:

- environmental or other governmental regulations, including changes in tax policy;
- weather conditions;
- increases in storage levels of crude oil, gas and produced water;
- increased use of alternative energy sources;
- decreased demand for crude oil, gas and produced water;
- continued fluctuation in commodity prices, including the prices of crude oil, gas and produced water;
- economic conditions;
- supply disruptions;
- availability of supply connected to our systems; and
- availability and adequacy of infrastructure to gather and process supply into and out of our systems.

The volumes of crude oil, gas and produced water gathered, processed and transported on our assets also depend on the production from the region that supplies our systems. Supply of crude oil, gas and produced water can be affected by many of the factors listed above, including commodity prices and weather. For instance, during 2018, we saw reduced drilling activity due to lower commodity prices and changes to the drilling plans of the operators with acreage dedicated to KFM, and we were unable to secure volumes from our Upstream business and third parties at levels we were projecting. Because we are substantially dependent on our Upstream business for a significant portion of our throughput, the reduced Upstream 2019 drilling program and any subsequent reductions in that program could significantly lower future volumes on the system if we are unable to find third-party customers.

In order to maintain or increase throughput levels on our system, we must obtain new sources of crude oil, gas and produced water. The primary factors affecting our ability to obtain non-dedicated sources of crude oil, gas, and produced water include (i) the level of successful leasing, permitting and drilling activity in our areas of operation, (ii) our ability to compete for volumes from new wells and (iii) our ability to compete successfully for volumes from sources connected to other pipelines. We anticipate that the reduced 2019 drilling program of our Upstream business may affect the production supply levels on our system. Additionally, we have no control over the level of drilling activity of third parties in our area of operation, the amount of reserves associated with wells connected to our system or the rate at which production declines from a well. In addition, we have no control over producers or their drilling or production decisions, which are affected by, among other things, the availability and cost of capital, levels of reserves, availability of drilling rigs and other costs of production and equipment.

Construction of certain midstream assets subjects us to risks of construction delays, cost over-runs, limitations on our growth and negative effects on our financial condition, results of operations or cash flows.

The construction of midstream assets is complex and subject to a number of factors beyond our control, including delays from third-party landowners, the permitting process, complying with laws, unavailability of materials, construction delays, labor disruptions, environmental hazards, financing, accidents, weather and other factors. Any delay in the completion of these midstream assets could adversely affect our financial condition, results of operations or cash flows. The construction of pipelines and gathering and processing and storage facilities requires the expenditure of significant amounts of capital, which may exceed our estimated costs. Estimating the timing and expenditures related to these development projects is very complex and subject to variables that can significantly increase expected costs. Should the actual costs of these projects exceed our estimates, our liquidity and capital position could be adversely affected. This level of development activity requires significant effort from our management and technical personnel. We may not have the ability to attract and/or retain the necessary number of personnel with the skills required to bring complicated projects to successful conclusions.

Our construction of new assets may be more expensive than anticipated and may not result in revenue increases and may be subject to regulatory, environmental, political, legal and economic risks that could adversely affect our financial condition, results of operations or cash flows.

The construction of additions or modifications to our existing systems and the construction of new midstream assets involve numerous regulatory, environmental, political and legal uncertainties beyond our control including potential protests or legal actions by interested third parties that may require the expenditure of significant amounts of capital. Financing may not be available on economically acceptable terms or at all. If we undertake these projects, we may not be able to complete them on

schedule, at the budgeted cost or at all. Moreover, our revenue may not increase due to the successful construction of a particular project.For instance, if we expand a pipeline or construct a new pipeline, the construction may occur over an extended period of time, and we may not receive any material increases in revenue promptly following completion of a project or at all.Further, we may construct facilities to capture anticipated future production growth in a region in which such growth does not materialize.As a result, new facilities may not be able to attract enough throughput to achieve our expected investment return, which could adversely affect our financial condition, results of operations or cash flows.In addition, the construction of additions to our existing gathering and processing assets will generally require us to obtain new rights-of-way and permits prior to constructing new pipelines or facilities. We may be unable to timely obtain such rights-of-way or permits to connect new product supplies to our existing gathering lines or capitalize on other attractive expansion opportunities.Additionally, it may become more expensive for us to obtain new rights-of-way or to expand or renew existing rights-of-way.If the cost of renewing or obtaining new rights-of-way increases, our cash flows could be adversely affected.

We may be unable to obtain or renew permits necessary for our operations which could inhibit our ability to do business.

Performance of our operations requires that we obtain and maintain a number of federal and state permits, licenses and approvals with terms and conditions containing a significant number of prescriptive limits and performance standards in order to operate. All of these permits, licenses, approval limits and standards require a significant amount of monitoring, record keeping and reporting in order to demonstrate compliance with the underlying permit, license, approval limit or standard. Noncompliance or incomplete documentation of our compliance status may result in the imposition of fines, penalties and injunctive relief. A decision by a government agency to deny or delay the issuance of a new or existing material permit or other approval, or to revoke or substantially modify an existing permit or other approval, could adversely affect our ability to initiate or continue operations at the affected location or facility, our financial condition, results of operations and cash flows.

Additionally, in order to obtain permits and renewals of permits and other approvals in the future, we may be required to prepare and present data to governmental authorities pertaining to the potential adverse impact that any proposed pipeline or processing-related activities may have on the environment, individually or in the aggregate. Certain approval procedures may require preparation of archaeological surveys, endangered species studies and other studies to assess the environmental impact of new sites or the expansion of existing sites. Compliance with these regulatory requirements is expensive and significantly lengthens the time required to prepare applications and to receive authorizations.

We typically do not obtain independent evaluations of hydrocarbon reserves; therefore, volumes we service in the future could be less than anticipated.

We typically do not obtain, on a regular basis, independent evaluations of hydrocarbon reserves connected to our gathering systems or that we otherwise service due to the unwillingness of producers to provide reserve information as well as the cost of such evaluations. Accordingly, other than reserve estimates with respect to our Upstream business, we do not have independent estimates of total reserves serviced by our assets or the anticipated life of such reserves. If the total reserves or estimated life of the reserves is less than we anticipate and we are unable to secure additional sources, then the volumes we gather and process could be lower, which would adversely affect our financial condition, results of operations or cash flows.

Our exposure to commodity price risk may change over time.

We generate substantially all of our revenue from our Midstream business pursuant to fee-based contracts under which we are paid based on the volumes that we gather, process and transport, rather than the underlying value of the commodity, in order to minimize our exposure to commodity price risk. However, we are a party to fee-based contracts that have a small portion of percent-of-proceeds contractual mix, but the portion of percent-of-proceeds does not exceed 6.0% for any one contract. In addition, we may acquire or develop additional midstream assets in a manner that increases our exposure to commodity price risk. Future exposure to the volatility of crude oil, gas and NGL prices could adversely affect our financial condition, results of operations or cash flows. Also, as with any acreage dedications, the profitability of those dedications depends on drilling activity that is often influenced by the behavior of commodity prices.

If third-party pipelines or other midstream facilities interconnected to our gathering, processing, storage or transportation systems become partially or fully unavailable, or if the volumes we gather, process, store or transport do not meet the quality requirements of the pipelines or facilities to which we connect, our gross profit and cash flow could be adversely affected.

Our Midstream assets connect to pipelines or facilities owned and operated by unaffiliated third parties. The continuing operation of, and our continuing access to, such third-party pipelines and other facilities is not within our control. These

pipelines, plants and other midstream facilities may become unavailable because of testing, turnarounds, line repair, maintenance, reduced operating pressure, lack of operating capacity, regulatory requirements and curtailments of receipt or deliveries due to insufficient capacity or because of damage from severe weather conditions or other operational issues. In addition, if our costs to access and transport on these third-party pipelines significantly increase, our profitability could be reduced. If any such increase in costs occurs, or if we lose access to these pipelines or other midstream facilities, or if the volumes we gather or transport do not meet their product quality requirements, our gross profit and cash flows could be adversely affected.

The midstream industry is highly competitive, and increased competitive pressure could adversely affect our financial condition, results of operations or cash flows.

We compete with similar midstream enterprises in our area of operation. The principal elements of competition are rates, terms of service and flexibility and reliability of service. Our competitors include large crude oil and gas companies that have greater financial resources and access to supplies of crude oil, gas and produced water than us. Some of these competitors may expand or construct gathering, processing, transportation and storage systems that would create additional competition for the services we provide to our customers. Excess pipeline capacity in the region served by our intrastate pipelines could also increase competition and adversely impact our ability to renew or enter into new contracts with respect to our available capacity when existing contracts expire. Our ability to renew or replace existing contracts with our customers at rates sufficient to maintain or increase current revenue and cash flows could be adversely affected by the activities of our competitors and customers. Further, gas utilized as a fuel competes with other forms of energy available to end-users, including electricity, coal and liquid fuels. Increased demand for such forms of energy at the expense of gas could lead to a reduction in demand for gas gathering, processing, storage and transportation services. All of these competitive pressures could adversely affect our financial condition, results of operations or cash flows.

If we do not make acquisitions on economically acceptable terms or efficiently and effectively integrate the acquired midstream assets with our existing asset base, our future growth will be limited.

Our ability to grow depends, in part, on our ability to make midstream acquisitions that result in an increase in cash generated from operations. If we are unable to make accretive acquisitions either because we are (1) unable to identify attractive acquisition candidates or negotiate acceptable purchase contracts with them, (2) unable to obtain financing for these acquisitions on economically acceptable terms or at all or (3) outbid by competitors, then our future growth will be limited.

From time to time, we may evaluate and seek to acquire midstream assets or businesses that we believe complement our existing business and related assets. We may acquire midstream assets or businesses that we plan to use in a manner materially different from its prior owner's use. Any acquisition involves potential risks, including:

- the inability to integrate the operations of recently acquired businesses or assets, especially if the assets acquired are in a new business segment or geographic area;
- the diversion of management's attention from other business concerns;
- the failure to realize expected volumes, revenue, profitability or growth;
- the failure to realize any expected synergies and cost savings;
- the coordination of geographically disparate organizations, systems and facilities;
- the assumption of unknown liabilities;
- the loss of customers or key employees from the acquired businesses; and
- potential environmental or regulatory liabilities and title problems.

The assessment by our management of these risks is inexact and may not reveal or resolve all existing or potential problems associated with an acquisition. Realization of any of these risks could adversely affect our financial condition, results of operations and cash flows. If we consummate any future acquisition, our capitalization and results of operations may change significantly.

We may not be able to retain existing Midstream customers or acquire new customers, which would reduce our revenue and limit our future profitability.

The renewal or replacement of our existing contracts with our Midstream customers at rates sufficient to maintain or increase current revenue and cash flows depends on a number of factors beyond our control, including competition from other midstream service providers and the price of, and demand for, crude oil, gas and NGLs in the markets we serve. The inability of

our management to renew or replace our current contracts as they expire and to respond appropriately to changing market conditions could have a negative effect on our profitability.

If our Midstream assets become subject to FERC regulation or federal, state or local regulations or policies change, our financial condition, results of operations and cash flows could be materially and adversely affected.

We believe that our gathering and transportation operations are exempt from regulation by FERC under the NGA. Section 1(b) of the NGA exempts gas gathering facilities from regulation by FERC under the NGA. Although FERC has not made any formal determinations with respect to any of our facilities, we believe that the gas pipelines in our gathering systems meet the traditional tests FERC has used to establish whether a pipeline is a gathering pipeline not subject to FERC jurisdiction. The distinction between FERC-regulated transmission services and federally unregulated gathering services, however, has been the subject of substantial litigation, and FERC determines whether facilities are gathering facilities on a case-by-case basis, so the classification and regulation of our gathering facilities may be subject to change based on future determinations by FERC, the courts, or Congress. If FERC were to consider the status of an individual facility and determine that the facility or services provided by us are not exempt from FERC regulation under the NGA, the rates for, and terms and conditions of, services provided by such facility would be subject to regulation by FERC under the NGPA and the rules and regulations promulgated under those statutes. Such regulation could decrease revenue, increase operating costs, and, depending upon the facility in question, could adversely affect our results of operations and cash flows.

Unlike gas gathering under the NGA, there is no exemption for the gathering of crude oil or NGLs under the ICA. Whether a crude oil or NGL shipment is in interstate commerce under the ICA depends on the fixed and persistent intent of the shipper as to the crude oil's or NGLs' final destination, absent a break in the interstate movement. We believe that the crude oil and NGL pipelines in our gathering system meet the traditional tests FERC has used to determine that a pipeline is not providing transportation service in interstate commerce subject to FERC ICA jurisdiction. However, the determination of the interstate or intrastate character of shipments on our crude oil and NGL pipelines depends on the shipper's intentions and the transportation of the crude oil or NGLs outside of our system, and may change over time. If FERC were to consider the status of an individual facility and the character of a crude oil or NGL shipment, and determine that the shipment is in interstate commerce, the rates for, and terms and conditions of, transportation services provided by such facility would be subject to regulation by FERC under the ICA. Such FERC regulation could change our current revenue stream, increase operating costs, and, depending on the facility in question, could adversely affect our results of operations and cash flows. In addition, if any of our facilities were found to have provided services or otherwise operated in violation of the ICA, this could result in the imposition of administrative and criminal remedies and civil penalties, as well as a requirement to disgorge charges collected for such services in excess of the rate established by FERC.

Other state and local regulations also affect our business. We are subject to some ratable take and common purchaser statutes in Oklahoma. Ratable take statutes generally require gatherers to take, without undue discrimination, gas production that may be tendered to the gatherer for handling. Similarly, common purchaser statutes generally require gatherers to purchase without undue discrimination as to source of supply or producer. These statutes have the effect of restricting our right as an owner of gathering facilities to decide with whom we contract to purchase or transport gas. Federal law leaves any economic regulation of gas gathering to the states, and Oklahoma has adopted complaint-based or other limited economic regulation of gas gathering activities.

Our operations are regulated, and we may incur significant costs and liabilities resulting from compliance with these regulations.

The pipelines we own and operate are subject to stringent and complex regulation related to pipeline safety and integrity management. The federal authority for pipeline safety is the Pipeline and Hazardous Materials Safety Administration ("PHMSA") of the U.S. Department of Transportation and is responsible for regulating the safety of design, construction, testing, operation, maintenance, and emergency response of U.S. oil and gas pipeline facilities. Compliance with PHMSA standards and regulations requires us to incur significant costs.In addition, violations of pipeline safety regulations can result in the imposition of significant penalties.

Several states have also passed legislation or promulgated rules to address pipeline safety. Compliance with pipeline integrity laws and other pipeline safety regulations issued by state agencies such as the OCC could result in substantial expenditures for testing, repairs and replacement. If our pipelines fail to meet the safety standards mandated by the OCC or the PHMSA regulations, then we may be required to repair or replace sections of such pipelines or operate the pipelines at a reduced maximum allowable operating pressure, the cost of which cannot be estimated at this time.

Due to the possibility of new or amended laws and regulations or reinterpretation of existing laws and regulations, there can be no assurance that future compliance with PHMSA or state requirements will not have a material adverse effect on our results of operations or financial position. Because certain of our operations are located around areas that may become more populated areas, such as the STACK play, we may incur expenses to mitigate noise, odor and light that may be emitted in our operations and expenses related to the appearance of our facilities. Municipal and other local or state regulations are imposing various obligations including, among other things, regulating the location of our facilities, imposing limitations on the noise levels of our facilities and requiring certain other improvements that increase the cost of our facilities. We are also subject to claims by neighboring landowners for nuisance related to the construction and operation of our facilities, which could subject us to damages for declines in neighboring property values due to our construction and operation of facilities.

In addition, the types and volumes of certain chemicals handled by our processing plants pose process safety management risks, including hazards related to the storage, handling and transportation of raw materials, products and wastes.These potential risks include pipeline and storage tank leaks and ruptures, explosions and fires, mechanical failure and chemical spills and other discharges or releases of toxic or hazardous substances or gases at our sites or during transportation. Managing these process hazards is heavily regulated under the Occupational Safety and Health Administration's Process Safety Management standard, and compliance with this standard can require significant expenditures.Moreover, violations of this standard can result in the imposition of significant penalties and the partial or total cessation of operations.

The potential adoption of federal, state and local legislative and regulatory initiatives intended to address potential induced seismic activity in the areas in which we operate could result in increased compliance costs and operating restrictions.

Our produced water disposal business is subject to existing laws and regulations with legal requirements that are subject to change which could affect our ability to operate the disposal wells. In response to recent seismic events near produced water disposal wells, federal and some state agencies are investigating whether such wells have contributed to increased seismic activity, and some states have imposed, or are considering imposing, additional requirements in the permitting of produced water disposal wells or otherwise to assess any relationship between seismicity and the use of such wells. For example, Oklahoma has taken numerous regulatory actions in response to concerns related to the operation of produced water disposal wells and induced seismicity, and has issued guidelines to operators in certain areas of the State curtailing injection of produced water due to seismic concerns. Some states have also restricted, suspended or shut down the use of certain disposal wells. Evaluation of seismic incidents and whether or to what extent those events are induced by the injection of produced water into disposal wells continues to evolve, as governmental authorities consider new and/or past seismic incidents in areas where produced water injection activities occur or are proposed to be performed. Court decisions or the adoption of any new laws, regulations or directives that restrict our ability to operate our disposal wells could have a material adverse effect on our financial condition and results of operations and cash flows.

In addition to the foregoing risks affecting our Midstream business, many of the risks that apply to our Upstream business also apply to our Midstream business.

Risks Related to Our Securities and Capital Structure

Our only significant asset is the ownership of the general partner interest and an approximate47% limited partner interest in SRII Opco, and such ownership may not be sufficient to enable us to satisfy our financial obligations, including under the Tax Receivable Agreement.

We have no direct operations and no significant assets other than the ownership of the general partner interest and an approximate47% limited partner interest in SRII Opco. We will depend on SRII Opco and its subsidiaries, including Alta Mesa and KFM, for distributions, loans and other payments to generate the funds necessary to meet our financial obligations. Subject to certain restrictions, SRII Opco generally is required to (i) make pro rata distributions to its partners, including us, in an amount at least sufficient to allow us to pay our taxes and (ii) reimburse us for certain corporate and other overhead expenses. However, legal and contractual restrictions in agreements governing future indebtedness of SRII Opco and its subsidiaries, including Alta Mesa and KFM, as well as the financial condition and operating requirements of Alta Mesa and KFM may limit our ability to obtain cash from SRII Opco. The earnings from or other available assets of SRII Opco and its subsidiaries, including Alta Mesa and KFM, may not be sufficient to enable us to satisfy our financial obligations. SRII Opco is treated as a partnership for U.S. federal income tax purposes and, as such, will not be subject to any entity-level U.S. federal income tax.Instead, taxable income will be allocated to holders of its SRII Opco Common Units, including us. As a result, we generally

will incur income taxes on our allocable share of any net taxable income of SRII Opco.Under the terms of the agreement of limited partnership of SRII Opco (the "SRII Opco LPA"), SRII Opco is obligated to make tax distributions to holders of its SRII Opco Common Units, including us, except to the extent such distributions would render SRII Opco insolvent or are otherwise prohibited by law or any of our current or future debt agreements. In addition to tax expenses, we also incur expenses related to our operations, our interests in SRII Opco and related party agreements, including payment obligations under the Tax Receivable Agreement, and expenses and costs of being a public company, all of which could be significant. See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Tax Receivable Agreement." To the extent that we need funds and SRII Opco or any of its subsidiaries is restricted from making such distributions under applicable law or regulation or under the terms of their financing arrangements, or are otherwise unable to provide such funds, it could materially adversely affect our liquidity and financial condition, including our ability to pay our income taxes when due.

Our stock price may be volatile.

The market prices of our Class A Common Stock and public warrants originally sold in our initial public offering ("Public Warrants") have been, and we expect them to continue to be, subject to significant volatility, and they have declined significantly from their prices on the closing date of the Business Combination. As of December 31, 2018, the reported closing price of our Class A Common Stock on NASDAQ was $1.00 per share and our Public Warrants was $0.07 per warrant. Such fluctuations could be in response to, among other things, the factors described in this "Risk Factors" section, or other factors, some of which are beyond our control, such as:

- actual or anticipated fluctuations in our quarterly financial results or the quarterly financial results of companies perceived to be similar to us;
- changes in the market's expectations about our operating results;
- success of our competitors;
- our operating results failing to meet the expectation of securities analysts or investors in a particular period;
- changes in financial estimates and recommendations by securities analysts concerning us or the market in general;
- negative perceptions about us based upon the presence of material weakness in internal control;
- outcome of the SEC investigation;
- operating and stock price performance of other companies that investors deem comparable to us;
- changes in laws and regulations affecting our business;
- commencement of, or involvement in, litigation involving us;
- changes in our capital structure, such as future issuances of securities or the incurrence of additional debt;
- the volume of shares of our Class A Common Stock available for public sale;
- any major change in our Board or management;
- sales of substantial amounts of Class A Common Stock by our directors, executive officers or significant stockholders or the perception that such sales could occur; and
- general economic and political conditions such as recessions, interest rates, fuel prices, international currency fluctuations and acts of war or terrorism.

Broad market and industry factors may materially harm the market price of our securities irrespective of our operating performance. The stock market in general and NASDAQ have experienced price and volume fluctuations that have often been unrelated or disproportionate to the operating performance of the particular companies affected. The trading prices and valuations of these stocks, and of our securities, may not be predictable. A loss of investor confidence in the market for retail stocks or the stocks of other companies which investors perceive to be similar to us could depress our stock price regardless of our business, prospects, financial conditions or results of operations. A decline in the market price of our securities also could adversely affect our ability to issue additional securities and our ability to obtain additional financing in the future.

Our securities may be delisted from NASDAQ.

Our Class A Common Stock and Public Warrants are currently listed on NASDAQ. However, we cannot assure you that we will be able to comply with the continued listing standards of NASDAQ.

We received letters on April 2, 2019, April 3, 2019 and May 14, 2019 from NASDAQ notifying us that we were not in compliance with NASDAQ Listing Rule 5250(c)(1) because we did not timely file this Annual Report on Form 10-K for the year ended December 31, 2018, we failed to maintain a minimum bid price of $1 per share and we did not timely file our Quarterly Report on Form 10-Q for the quarter ended March 31, 2019. We submitted a plan to NASDAQ on May 29, 2019 to

regain compliance with NASDAQ Listing Rule 5250(c)(1) to allow for continued listing.Our plan was accepted by NASDAQ and we were granted an extension until September 30, 2019, to regain compliance with NASDAQ's filing requirements.

If we fail to comply with the continued listing standards of NASDAQ, our securities may become subject to delisting. If NASDAQ delists our Class A Common Stock or Public Warrants from trading on its exchange for failure to meet the continued listing standards, we and our security holders could face significant material adverse consequences including:

- a limited availability of market quotations for our securities;
- a limited amount of analyst coverage; and
- a decreased ability for us to issue additional securities or obtain additional financing in the future.

If securities or industry analysts do not publish or cease publishing research or reports about us, our business, or our market, or if they change their recommendations regarding our securities adversely, the price and trading volume of our securities could decline.

The trading market for our securities may be influenced by the research and reports that industry or securities analysts may publish about us, our business, our market, or our competitors. We have seen the number of analysts covering our stock reduce to just one.This could limit the interest in our securities and negatively affect their price. We do not have any control over the research and reports published or if they will be published at all. If any analysts who may cover us today or in the future make negative recommendation regarding our securities adversely, or provide more favorable relative recommendations about our competitors, the price of our securities could decline.The loss of the remaining analyst could cause our stock price or trading volume to decline.

There is no guarantee that our Public Warrants will be in the money at a time when they are exercisable, and they may expire worthless; the terms of our Public Warrants may be amended without the consent of all holders.

The exercise price for our Public Warrants is $11.50 per share and our common stock closed at $0.146 per share on June 28, 2019.Accordingly, the Public Warrants are significantly underwater and may not be in the money at a time when they are exercisable, and as such, the Public Warrants may expire worthless.

In addition, the warrant agreement between Continental Stock Transfer & Trust Company, as warrant agent, and us provides that the terms of the Public Warrants may be amended without the consent of any holder to cure any ambiguity or correct any defective provision, but requires the approval by the holders of at least 50% of the then outstanding Public Warrants to make any change that adversely affects the interests of the registered holders. Accordingly, we may amend the terms of the Public Warrants in a manner adverse to a holder if holders of at least 50% of the then outstanding Public Warrants approve of such amendment. Although our ability to amend the terms of the Public Warrants with the consent of at least 50% of the then outstanding Public Warrants is unlimited, examples of such amendments could be amendments to, among other things, increase the exercise price of the Public Warrants, shorten the exercise period or decrease the number of shares of our Class A Common Stock purchasable upon exercise of a Public Warrant.

We may redeem the Public Warrants prior to their exercise at a time that is disadvantageous to holders, thereby making their Public Warrants worthless.

We have the ability to redeem the outstanding Public Warrants at any time after they become exercisable and prior to their expiration at a price of $0.01 per warrant, provided that (i) the last reported sale price of our Class A Common Stock equals or exceeds $18.00 per share for any 20 trading days within the 30 trading-day period ending on the third business day before we send the notice of such redemption and (ii) on the date we give notice of redemption and during the entire period thereafter until the time the Public Warrants are redeemed, there is an effective registration statement under the Securities Act covering the shares of our Class A Common Stock issuable upon exercise of the Public Warrants and a current prospectus relating to them is available or we have elected to require the exercise of the Public Warrants on a cashless basis. Redemption of the outstanding Public Warrants could force holders of Public Warrants:

- to exercise their Public Warrants and pay the exercise price therefor at a time when it may be disadvantageous for them to do so;
- to sell their Public Warrants at the then-current market price when they might otherwise wish to hold their Public Warrants; or
- to accept the nominal redemption price which, at the time the outstanding Public Warrants are called for redemption, is likely to be substantially less than the market value of their Public Warrants.

Anti-takeover provisions contained in our Charter and bylaws, as well as provisions of Delaware law, could impair a takeover attempt.

Our Charter and bylaws contain provisions that could have the effect of delaying or preventing changes in control or changes in our management without the consent of our Board. These provisions include:

- up to two of our nine directors may be appointed by the holders of the Series A Preferred Stock and up to three of our directors may be appointed by holders of the Series B Preferred Stock without any vote of the holders of Class A Common Stock;
- a board that is classified into three classes of directors with staggered three-year terms;
- no cumulative voting in the election of directors, which limits the ability of minority stockholders to elect director candidates;
- the exclusive right of our Board to elect a director to fill a vacancy created by an increase in the number of directors to serve on our Board or the resignation, death, or removal of a director, which prevents stockholders from being able to fill vacancies on our Board;
- the ability of our Board to determine whether to issue shares of our preferred stock and to determine the price and other terms of those shares, including preferences and voting rights, without stockholder approval, which could be used to significantly dilute the ownership of a hostile acquirer;
- a prohibition on stockholder action by written consent, which forces stockholder action to be taken at an annual or special meeting of our stockholders;
- the requirement that an annual meeting of stockholders may be called only by the chairman of the Board, the chief executive officer, or the Board, which may delay the ability of our stockholders to force consideration of a proposal or to take action, including the removal of directors;
- limiting the liability of, and providing indemnification to, our directors and officers;
- controlling the procedures for the conduct and scheduling of stockholder meetings;
- providing that directors may be removed prior to the expiration of their terms by stockholders only for cause; and
- advance notice procedures that stockholders must comply with in order to nominate candidates to our Board or to propose matters to be acted upon at a stockholders' meeting, which may discourage or deter a potential acquirer from conducting a solicitation of proxies to elect the acquirer's own slate of directors or otherwise attempting to obtain control of us.

These provisions, alone or together, could delay hostile takeovers and changes in control of us or changes in our Board and management.

As a Delaware corporation, we are also subject to provisions of Delaware law, including Section 203 of the Delaware General Corporation Law, which prevents some stockholders holding more than 15% of our outstanding voting common stock from engaging in certain business combinations without approval of the holders of substantially all of our outstanding voting common stock.Any provision of our Charter or bylaws or Delaware law that has the effect of delaying or deterring a change in control could limit the opportunity for our stockholders to receive a premium for their securities and could also affect the price that some investors are willing to pay for our securities.

If a significant portion of our total outstanding shares were sold into the market in the near future, the market price of our Class A Common Stock could drop significantly.

Sales of a substantial number of shares of Class A Common Stock in the public market could occur at any time. The holders of our founder shares, which include Silver Run Sponsor II, LLC (our "Sponsor") and independent directors, and Fund VI Holdings own approximately 36% of our Class A Common Stock that is currently outstanding. In addition, the Contributors have a redemption or exchange right with respect to all of their respective SRII Opco Common Units. If the Contributors and their permitted transferees redeem or exchange all of their SRII Opco Common Units for shares of Class A Common Stock, they will collectively own approximately 53% of our Class A Common Stock following such redemption or exchange. The sale by these holders of a large number of shares, or the perception in the market that the holders of a large number of shares intend to sell shares, could reduce the market price of our Class A Common Stock.

A significant percentage of our outstanding voting common stock is held by High Mesa Holdings and our Sponsor.

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High Mesa Holdings, together with its affiliates, and our Sponsor, together with its affiliates, beneficially own approximately 35% and 22%, respectively, of our voting common stock. As long as these entities own or control a significant percentage of outstanding voting power, they will each have the ability to strongly influence all corporate actions requiring stockholder approval, including the election and removal of directors and the size of our Board, any amendment of Charter or bylaws, or the approval of any merger or other significant corporate transaction, including a sale of substantially all of our assets.

The interests of High Mesa Holdings and our Sponsor and their respective affiliates may not align with the interests of our other stockholders.Our Sponsor is in the business of making investments in companies and may acquire and hold interests in businesses that compete directly or indirectly with us. Our Sponsor and its affiliates may also pursue acquisition opportunities that may be complementary to our business, and, as a result, those acquisition opportunities may not be available to us. In addition, our Charter provides that we renounce any interest or expectancy in the business opportunities of our officers and directors and their respective affiliates and each such party shall not have any obligation to offer us those opportunities unless presented to one of our directors or officers in his or her capacity as a director or officer.

We will be required to make payments under the Tax Receivable Agreement for certain tax benefits we may claim, and the amounts of such payments could be significant.

In connection with the completion of the Business Combination, we entered into the Tax Receivable Agreement with the AM Contributor and the Riverstone Contributor (the "Initial Limited Partners") and SRII Opco. Pursuant to the Tax Receivable Agreement, we will be required to make cash payments to the Initial Limited Partners and their permitted transferees (together, the "TRA Holders") equal to 85% of the amount of tax benefits, if any, that we actually realize (or are deemed to realize in certain circumstances) in periods after the Business Combination as a result of (i) certain tax basis increases resulting from the exchange of SRII Opco Common Units for Class A Common Stock (or, under certain circumstances, cash) pursuant to the redemption right or our right to effect a direct exchange of SRII Opco Common Units under the SRII Opco LPA, other than such tax basis increases allocable to assets held by KFM or otherwise used in our Midstream business, and (ii) interest paid or deemed to be paid by us as a result of, and additional tax basis arising from, any payments we make under the Tax Receivable Agreement.We will retain the benefit of the remaining 15% of these cash savings. The amount of the cash payments that we may be required to make under the Tax Receivable Agreement could be significant and is dependent upon significant future events and assumptions, including the timing of the exchanges of SRII Opco Common Units, the price of our Class A Common Stock at the time of each exchange, the extent to which such exchanges are taxable transactions and the amount of the exchanging TRA Holder's tax basis in its SRII Opco Common Units at the time of the relevant exchange.The amount of such cash payments is also based on assumptions as to the amount and timing of taxable income we generate in the future, the U.S. federal income tax rate then applicable and the portion of our payments under the Tax Receivable Agreement that constitute interest or give rise to depreciable or amortizable tax basis. Moreover, payments under the Tax Receivable Agreement will be based on the tax reporting positions that we determine, which tax reporting positions are subject to challenge by taxing authorities. We will be dependent on distributions from SRII Opco to make payments under the Tax Receivable Agreement, and we cannot guarantee that such distributions will be made in sufficient amounts or at the times needed to enable us to make our required payments under the Tax Receivable Agreement, or at all. Any payments made by us to the TRA Holders under the Tax Receivable Agreement will generally reduce the amount of overall cash flow that might have otherwise been available to us. To the extent that we are unable to make timely payments under the Tax Receivable Agreement for any reason, the unpaid amounts will be deferred and will accrue interest until paid by us. Nonpayment for a specified period may constitute a breach of a material obligation under the Tax Receivable Agreement, and therefore, may accelerate payments due under the Tax Receivable Agreement. The payments under the Tax Receivable Agreement are also not conditioned upon the TRA Holders maintaining a continued ownership interest in SRII Opco or us.See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Tax Receivable Agreement" for a discussion of the Tax Receivable Agreement and the related likely benefits to be realized by us and the TRA Holders.

We will not be reimbursed for any payments made to TRA Holders under the Tax Receivable Agreement in the event that any tax benefits are disallowed.

We will not be reimbursed for any cash payments previously made to the TRA Holders pursuant to the Tax Receivable Agreement if any tax benefits initially claimed by us are subsequently challenged by a taxing authority and are ultimately disallowed.Instead, any excess cash payments made by us to a TRA Holder will be netted against any future cash payments that we might otherwise be required to make under the terms of the Tax Receivable Agreement. However, a challenge to any tax benefits initially claimed by us may not arise for a number of years following the initial time of such payment or, even if challenged early, such excess cash payment may be greater than the amount of future cash payments that we might otherwise be required to make under the terms of the Tax Receivable Agreement and, as a result, there might not be future cash payments

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from which to net against. The applicable U.S. federal income tax rules are complex and factual in nature, and there can be no assurance that the Internal Revenue Service or a court will not disagree with our tax reporting positions. As a result, it is possible that we could make cash payments under the Tax Receivable Agreement that are substantially greater than our actual cash tax savings. See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Tax Receivable Agreement" for a discussion of the Tax Receivable Agreement and the related likely benefits to be realized by us and the TRA Holders.

Certain of the TRA Holders have substantial control over us, and their interests, along with the interests of other TRA Holders, in our business may conflict with the holders of our Class A Common Stock.

The TRA Holders may receive payments from us under the Tax Receivable Agreement upon any redemption or exchange of their SRII Opco Common Units, including the issuance of shares of our Class A Common Stock upon any such redemption or exchange. As a result, the interests of the TRA Holders may conflict with the interests of holders of our Class A Common Stock. For example, the TRA Holders may have different tax positions from us which could influence their decisions regarding whether and when to dispose of assets, whether and when to incur new or refinance existing indebtedness, especially in light of the existence of the Tax Receivable Agreement, and whether and when we should terminate the Tax Receivable Agreement and accelerate our obligations thereunder. In addition, the structuring of future transactions may take into consideration tax or other considerations of TRA Holders even in situations where no similar considerations are relevant to us. See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Tax Receivable Agreement" for a discussion of the Tax Receivable Agreement and the related likely benefits to be realized by us and the TRA Holders.

In certain cases, payments under the Tax Receivable Agreement may be accelerated and/or significantly exceed the actual benefits, if any, we realize in respect of the tax attributes subject to the Tax Receivable Agreement.

The Tax Receivable Agreement provides that if we breach any of our material obligations under the Tax Receivable Agreement or if, at any time, we elect an early termination of the Tax Receivable Agreement, then the Tax Receivable Agreement will terminate and our obligations, or our successor's obligations, to make payments under the Tax Receivable Agreement would accelerate and become immediately due and payable. The amount due and payable in those circumstances is determined based on certain assumptions, including an assumption that we would have sufficient taxable income to fully utilize all potential future tax benefits that are subject to the Tax Receivable Agreement. We may need to incur debt to finance payments under the Tax Receivable Agreement to the extent our cash resources are insufficient to meet our obligations under the Tax Receivable Agreement as a result of timing discrepancies or otherwise.

As a result of the foregoing, (i) we could be required to make cash payments to the TRA Holders that are greater than the specified percentage of the actual benefits we ultimately realize in respect of the tax benefits that are subject to the Tax Receivable Agreement, and (ii) we would be required to make a cash payment equal to the present value of the anticipated future tax benefits that are the subject of the Tax Receivable Agreement, which payment may be made significantly in advance of the actual realization, if any, of such future tax benefits. In these situations, our obligations under the Tax Receivable Agreement could have a substantial negative impact on our liquidity and could have the effect of delaying, deferring or preventing certain mergers, asset sales, other forms of business combination, or other changes of control due to the additional transaction costs a potential acquirer may attribute to satisfying such obligations. There can be no assurance that we will be able to finance our obligations under the Tax Receivable Agreement.

Non-U.S. holders may be subject to U.S. income tax with respect to gain on disposition of their Class A Common Stock and Public Warrants.

We believe that we are a United States real property holding corporation (a "USRPHC"). As a result, non-U.S. holders that own (or are treated as owning under constructive ownership rules) more than a specified amount of our Class A Common Stock or Public Warrants during a specified time period may be subject to U.S. federal income tax on a sale, exchange, or other disposition of such Class A Common Stock or Public Warrants and may be required to file a U.S. federal income tax return. If you are a Non-U.S. holder, we urge you to consult your tax advisors regarding the tax consequences of such treatment.

Item 1B. Unresolved Staff Comments.

None.

Item 2. Properties

Upstream Segment

Overview

As of December 31, 2018, we have a highly contiguous position of 140,400 net acres in the up-dip, naturally-fractured oil portion of the STACK, primarily in eastern Kingfisher and south-eastern Major Counties in Oklahoma. Our drilling locations primarily target the Osage, Meramec and Oswego formations. This position is characterized by multiple productive zones located at total vertical depths between 4,000 feet and 8,000 feet.

At December 31, 2018, we had a 66% average working interest in 786 gross producing wells.At December 31, 2018, we had six horizontal drilling rigs operating in the STACK, but by late February 2019, we had no rigs operating.We restarted our development program in March 2019 and expected to use 2 rigs for the remainder of 2019 as we focused on the optimal completion design, well pattern and lowering well costs.Following the August 2019 borrowing base redetermination, we have decided to operate 1 rig starting in September.We will continue to evaluate how much, if any, upstream development will take place going forward.

Bayou City Joint Development Agreement

In January 2016, we entered into a joint development agreement (as subsequently amended, the "JDA") with BCE-STACK Development LLC ("BCE"), a fund advised by Bayou City Management, LLC, to fund a portion of our drilling operations with the intent to accelerate our development. The JDA establishes a development plan of 60 wells in three tranches, and provides

opportunities for the parties to potentially agree to an additional 20 wells. As of December 31, 2018, 61 joint wells had been drilled or spudded.

Under the JDA, up to 100% of our well costs could be funded up to a specified total well cost. We are responsible for any drilling and completion costs exceeding approved amounts. In exchange for BCE carrying the drilling and completion costs, they receive 80% of our working interest in each funded well until attaining a 15% internal rate of return for the entire tranche, at which time their interest reduces to 20%.If a tranche attains a 25% internal rate of return, their interest reduces to 12.5%.

During the Successor Period, we brought 25 horizontal wells on production that were funded through the JDA. AtDecember 31, 2018, there were no funded horizontal wells in progress, and we do not expect any wells to be developed in 2019 pursuant to the JDA.On June 11, 2019, we received a letter from BCE noticing us of alleged defaults under the JDA. We dispute these allegations and intend to vigorously defend ourselves.

Our Oil and Gas Reserves

Our proved reserves and production profile as of December 31, 2018 was as follows:

Total Estimated Proved Reserves (MMBoe)	Percent Proved Developed (1)	Liquids as a Percentage of Total Proved Reserves (1)	PV-10 ($ in millions) (2)	Standardized Measure ($ in millions) (2)	Net Acreage (3)	Net Producing Wells (4)	Average 2018 Daily Net Production (MBoe/d) (5)
69.1	100%	65%	$812.9	$714.3	140,400	517.9	31.1

(1) Computed as a percentage of total proved reserves. Based on our April 2019 assessment of our ability to continue as a going concern and our expected inability to fund development costs, we removed a total of 89,073 MBoe of PUDs as of December 31, 2018.

(2) PV-10 is a non-GAAP measure of the estimated future net cash flows from proved reserves before giving effect to income taxes, discounted at an annual rate of 10 percent. The calculation of PV-10 also does not give effect to derivatives or hedging transactions. Standardized measure is the after-tax estimated future net cash flows from proved reserves discounted at an annual rate of 10 percent and may (depending upon a registrant's derivative and hedging policy) include the effects of hedges, all determined in accordance with GAAP. We believe PV-10 is a useful measure of the value of our proved reserves because it allows users of our financial statements to compare relative values and sizes of proved reserves among exploration and production companies without regard to their corporate structure and the resulting income tax burden. The difference between PV-10 and standardized measure is the discounted effect of income taxes, totaling $98.6 million, on our share of expected future net cash flows, without taking into consideration the utilization of net operating loss carryforwards or other tax credits.

(3) Includes developed and undeveloped acreage.

(4) Calculated as gross wells multiplied by our working interest percentage for each well.

(5) Average daily net production for the Successor Period.

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Key information and assumptions used in determining our estimated net proved reserves at the end of each period is set forth in Item 8. All of our reserves are located in the United States. The information presented during the Predecessor Periods includes amounts related to discontinued operations.

Oil and NGLS (Mbbls)	**Successor**	**Predecessor**		
	December 31, 2018	**February 8, 2018**	**December 31, 2017**	**December 31, 2016**
Proved Reserves (1)				
Developed	45,064	30,693	32,527	24,809
Undeveloped	—	77,256	77,878	61,280
Total	45,064	107,949	110,405	86,089
Average market prices (per bbl) - oil(2)	$ 65.56	$ 52.89	$ 51.34	$ 42.75
Average realized prices (per bbl) - NGLs(2)	$ 22.44	$ 27.48	$ 26.06	$ 15.18

Natural Gas (MMcf)	**Successor**	**Predecessor**		
	December 31, 2018	**February 8, 2018**	**December 31, 2017**	**December 31, 2016**
Proved Reserves (1)				
Developed	144,148	126,231	150,183	93,361
Undeveloped	—	284,571	283,336	222,644
Total	144,148	410,802	433,519	316,005
Average market prices (per MMBtu) - natural gas(2)	$ 3.10	$ 2.99	$ 2.98	$ 2.49

Total (MBoe)	**Successor**	**Predecessor**		
	December 31, 2018	**February 8, 2018**	**December 31, 2017**	**December 31, 2016**
Proved Reserves (1)				
Developed	69,089	51,731	57,557	40,371
Undeveloped	—	124,685	125,101	98,386
Total	69,089	176,416	182,658	138,757

(1) Proved reserves were calculated using oil and gas parameters established by current SEC guidelines and accounting rules. Reserve estimates are based on various assumptions, including assumptions required by the SEC relating to oil and gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. Actual future production, oil and gas prices, revenue, taxes, development expenditures, operating expenses and quantities of recoverable oil and gas reserves may vary from these estimates. In addition, we may adjust our estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and gas prices and other factors, many of which are beyond our control. Sustained lower prices may result in the estimated quantities and present values of our reserves being reduced and may necessitate future impairments of our capitalized costs.

(2) Average market prices represent an unweighted arithmetic average of the market price on the first day of each month during the last 12 months.

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Proved Undeveloped Reserves

The information presented during the Predecessor Periods includes amounts related to discontinued operations.Changes in our proved undeveloped reserves were (in MBoe):

	Successor	Predecessor		
	February 9, 2018 Through December 31, 2018	January 1, 2018 Through February 8, 2018	Year Ended December 31, 2017	Year Ended December 31, 2016
Beginning of period	124,685	125,101	98,386	44,624
Converted into proved developed reserves	(18,999)	—	(4,083)	(1,509)
Extensions and discoveries	43,354	—	32,972	51,306
Reserves acquired	3,738	—	1,846	—
Reserves sold/distributed[(1)]	—	(1,129)	(746)	—
Revisions[(2)]	(152,778)	713	(3,274)	3,965
End of period	—	124,685	125,101	98,386
Percentage of total proved reserves	—%	71%	68%	71%

(1) Reserves sold/distributed during the period January 1, 2018 to February 8, 2018, represent amounts related to our non-STACK properties that are classified as discontinued operations in our consolidated financial statements.

(2) Effective as of December 31, 2018, due to uncertainty regarding our ability to continue as a going concern and the availability of capital that would be required to develop the proved undeveloped reserves, we have removed all of our PUDs from our total estimated proved reserves.

During the Successor Period, we incurred approximately $160.6 million in expenditures to develop PUD reserves. PUD reserves may only be booked if they relate to wells scheduled to be drilled within five years of the original date of their recognition. The identification and development of PUDs in the future is dependent on future commodity prices, costs, capital availability and other economic assumptions.During January 2019, we finalized our development plan for the next five years and received an audit report from our outside engineers that agreed with our recognition of PUDs for the majority of that future development. During April 2019, in finalizing our financial reporting for 2018, we determined that we may fail to satisfy the leverage covenant under the Alta Mesa RBL during 2019. Accordingly, we were unable to conclude that we would have a high likelihood of continued access to that capital source. Thus, we concluded that we did not satisfy the ability-to-drill threshold under the SEC's reserve recognition rule with respect to our future drilling locations and did not recognize any proved undeveloped locations in our final December 31, 2018 reserve report received in April 2019. Should our ability to fund the required development costs improve in the future, we expect to recognize all or a portion of those resources as proved.

Internal Controls Over Reserve Estimates and Qualifications of Technical Persons

Our policies and practices regarding internal controls over reserve recognition are structured to objectively and accurately estimate our oil and gas reserves quantities and their present value in compliance with SEC standards. The reserve estimation process begins with our Corporate Reserves department, which gathers and analyzes much of the data used as inputs to estimating reserves. Working and net revenue interests are sourced from our division order system in our land department. Lease operating expenses are provided by our accounting department and our operations team provides capital expenses. Our Vice President of Planning and Reserves is the technical person primarily responsible for overseeing the preparation of our reserve estimates. His qualifications include the following:

- Over 30 years of practical experience in petroleum engineering and in the estimation and evaluation of reserves; and
- Bachelor of Science Degree in Petroleum Engineering from the University of Texas in 1980, Master of Business Administration from Oklahoma City University in 1988.

Our methodologies include reviews of production trends, material balance calculations, analogy to comparable properties, and volumetric analysis, with performance methods preferred. Reserve estimates for developed non-producing properties and for undeveloped properties are based primarily on analogy to offset production in the same area.

We maintain internal controls that we believe result in the proper amount and value of our reported reserves. These controls, which we determined to be effective for all periods presented, include:

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- we follow comprehensive SEC-compliant internal policies to determine and report proved reserves;
- reserve estimates are made by experienced reservoir engineers or under their direct supervision; and
- annually, our Chief Operating Officer and Chief Executive Officer review all significant reserves changes and all new proved undeveloped reserves additions.

Ryder Scott Company, LP ("Ryder Scott"), a third-party petroleum engineering consulting firm, audited approximately 96% of our 2018 proved reserves on a 6:1 Mcf per Bbl conversion basis. Their report is filed with this Annual Report as Exhibit 99.1. The reserve audit by Ryder Scott conformed to the meaning of "reserves audit" as presented in the SEC's Regulation S-K, Item 1202. The qualifications of the technical person at Ryder Scott primarily responsible for overseeing the audit of our reserve estimates are set forth below.

Miles R. Palke earned a B.S. in Petroleum Engineering from Texas A&M University in College Station, Texas and a Master of Science in Petroleum Engineering from Stanford University in Palo Alto California. Mr. Palke graduated Magna Cum Laude and with University Honors from Texas A&M University and is a registered Professional Engineer in the State of Texas. Based on his educational background, professional training and more than 22 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Palke has attained the professional qualifications as a Reserves Estimator and Reserves Auditor set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers.

A reserves audit and a financial audit are separate activities with unique and different processes and results. A reserves audit under SEC standards is the process of reviewing certain of the pertinent facts interpreted and assumptions underlying a reserves estimate prepared by another party and the rendering of an opinion about the appropriateness of the methodologies employed, the adequacy and quality of the data relied upon, the depth and thoroughness of the reserves estimation process, the classification of reserves appropriate to the relevant definitions used, and the reasonableness of the estimated reserves quantities.

Oil and Gas Production, Production Prices and Production Costs

Information relating to our oil and gas production, sales prices for our products produced and production costs is included in Item 1.

Drilling and Other Exploratory and Development Activities

	Successor	Predecessor		
	February 9, 2018 Through December 31, 2018	January 1, 2018 Through February 8, 2018	Year Ended December 31, 2017	Year Ended December 31, 2016
Development wells (net):				
Productive	123.8	7.0	59.0	29.9
Dry	—	—	—	—
Total development wells	123.8	7.0	59.0	29.9
Exploratory wells (net):				
Productive	—	—	0.1	3.0
Dry	1.0	—	—	—
Total exploratory wells	1.0	—	0.1	3.0

Activities at Year End

At December 31, 2018, we had 32 gross (26 net) wells that were in progress for drilling or completion operations.

Delivery Commitments

Information about our firm transportation commitments is included in Part II, Item 7.

Productive Wells, Developed and Undeveloped Acreage

The following sets forth information with respect to our wells and acreage under lease as of December 31, 2018, all of which is located in the United States:

	December 31, 2018	
	Gross	Net
Number of productive wells principally targeting[(1)]:		
Oil	760	502.6
Gas	26	15.3
Total wells	786	517.9
Properties:		
Developed acres	166,955	112,088
Undeveloped acres	53,741	28,314
Total acres	220,696	140,402
Undeveloped acreage expirations [(2)]:		
Year ending December 31, 2019	13,942	7,213
Year ending December 31, 2020	14,183	5,636
Year ending December 31, 2021	12,778	6,493
Total	40,903	19,342

(1) Productive wells are producing wells and those wells we deem capable of production. A gross well is a well in which a working interest is owned. The number of net wells represents the sum of fractional working interests we own in gross wells, including joint development wells.

(2) Our lease acreage is typically subject to expirations if a well is not drilled and producing before the end of the primary term. The primary term of our leasehold ranges from 3 to 5 years. As is customary in our industry, our undeveloped leasehold may be maintained through: (i) commencing operations for drilling, completion and production, (ii) pooling, (iii) extensions or renewals and (iv) other operational extensions, including shut-in payments and continuous operations. As of December 31, 2018, the majority of our undeveloped acreage subject to expiry does not have associated proved reserves. We believe that our lease terms are similar to our competitors' fee lease terms as they relate to both primary term and royalty interests.

Title to Properties

We typically conduct a preliminary review of title records, which may include opinions or reports of appropriate professionals or counsel, at the time we acquire properties. We believe that title to our interests is satisfactory and consistent with the standards in our industry. The interests owned by us may be subject to one or more royalty, overriding royalty net profits interests, liens and taxes or other outstanding interests (including disputes related to such interests) customary in the industry.

Midstream Segment

Our KFM assets include a gas and oil gathering network, a cryogenic gas processing plant with off-take capacity, field compression facilities and a produced water disposal system. These assets are located in the Anadarko Basin in Oklahoma.

KFM has also expanded its gas gathering system northward into Major County, Oklahoma, with a high-pressure line to connect the existing system in Kingfisher County, Oklahoma to new low-pressure gathering pipelines in southeastern Major County.

KFM holds a 50% equity interest in a partnership to develop a long-haul crude oil pipeline project, the Cimarron Express Pipeline ("Cimarron"), that was designed to link the existing crude oil storage tank located at the KFM Lincoln Terminal to a crude oil terminal site at Cushing, Oklahoma. Based on lower oil prices, less down spacing of development wells, and lower expected volumes from wells, we determined in the fourth quarter of 2018 that the project was not likely to be completed and recognized an impairment to reduce our investment to its estimated fair value.

In November 2018, Alta Mesa sold substantially all of its produced water assets to a subsidiary of KFM, consisting of over 200 miles of produced pipelines, and related facilities and equipment, along with 20 produced water disposal wells, surface leases, easements and other agreements, net of related obligations.

Item 3. Legal Proceedings

We are subject to legal proceedings, claims and liabilities arising in the ordinary course of business, the outcomes of which cannot be reasonably estimated. Accruals for losses associated with litigation are made when losses are deemed probable and can be reasonably estimated.Because legal proceedings are inherently unpredictable and unfavorable resolutions could occur, assessing contingencies is highly subjective and requires judgments about uncertain future events. When evaluating contingencies, we may be unable to provide a meaningful estimate due to a number of factors, including the procedural status of the matter in question, the presence of complex or novel legal theories, and/or the ongoing discovery and development of information important to the matters.

Litigation

On January 30, 2019, the Company, James T. Hackett, our interim Chief Executive Officer and Chairman of the Board, certain of our former and current directors, Thomas J. Walker, our former Chief Financial Officer, and Riverstone Investment Group LLC were named as defendants in a putative securities class action filed in the United States District Court for the Southern District of New York ("SDNY Complaint").The plaintiff, Plumbers and Pipefitters National Pension Fund, alleges that the defendants disseminated a false and misleading proxy statement in connection with the Business Combination and, therefore, violated Section 14(a) of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), and Rule 14-9 promulgated thereunder. In addition, the plaintiff alleges that Riverstone and the individual defendants violated Section 20(a) of the Exchange Act. The plaintiff is seeking compensatory and/or rescissory damages against the defendants.The District Court transferred this action to the U.S. District Court for the Southern District of Texas.

On March 14 and 19, 2019, two additional putative securities class action complaints were filed in the U.S. District Court for the Southern District of Texas ("SDTX Complaints") against the same defendants named in the SDNY Complaint, and Harlan H. Chappelle and Michael A. McCabe, our former President and Chief Executive Officer and Chief Financial Officer, respectively.These complaints include the same claims asserted in the initial complaint, but also add claims under Section 10(b) of the Exchange Act and Rule 10b-5 promulgated thereunder against us and certain of our current and former officers and directors on behalf of all persons or entities who purchased or otherwise acquired Silver Run or AMR securities between March 24, 2017, and February 25, 2019.The new claims are based upon alleged misstatements contained in our proxy statement and made after the Business Combination. The plaintiffs seek compensatory and/or rescissory damages against the defendants.

The outcome of the above securities class action complaints is uncertain, and while we believe that we have valid defenses to the plaintiff's claims and intend to defend the lawsuits vigorously, no assurance can be given as to the outcome of the lawsuits.

On March 1, 2017, Mustang Gas Products, LLC ("Mustang") filed suit in the District Court of Kingfisher County, Oklahoma, against Oklahoma Energy Acquisitions, LP, and eight other entities, including certain of our affiliates and subsidiaries. Mustang alleges that (1) Mustang is a party to gas purchase agreements with Oklahoma Energy containing gas dedication covenants that burden land, leases and wells in Kingfisher County, Oklahoma, and (2) Oklahoma Energy, in concert with the other defendants, has wrongfully diverted gas sales to KFM in contravention of these agreements. Mustang asserts claims for declaratory judgment, anticipatory repudiation and breach of contract against Oklahoma Energy only. Mustang also claims tortious interference with contract, conspiracy, and unjust enrichment/constructive trust against all defendants. We believe that the allegations contained in this lawsuit are without merit and intend to vigorously defend ourselves.

In August 2017, Biloxi Marsh Lands ("Biloxi") filed suit in the 34th District Court for the Parish of St. Bernard, Louisiana, against Meridian Resource & Exploration LLC (a subsidiary of HMI), Alta Mesa, and other defendants. Biloxi alleges negligent construction, installation, maintenance, use and operation of a pipeline. In lieu of litigating corporate structure allegations and to reduce potential litigation expenses, Alta Mesa stipulated with respect to Biloxi that it would be bound by and assume liability and responsibility for any unpaid debts, obligations or final judgments that may be entered against Meridian in favor of Biloxi in this matter.However, these allegations relate to non-STACK oil and gas assets that Alta Mesa distributed to a subsidiary of HMI prior to the Business Combination.In connection with that distribution, certain HMI subsidiaries agreed to indemnify and hold Alta Mesa harmless from any liabilities associated with those non-STACK oil and gas assets, regardless of when those liabilities arose. Consequently, we believe that any potential damages incurred by Alta Mesa or Meridian as a result of these allegations are the responsibility of HMI. There is no guarantee that HMI will pay any settlement amounts or judgments rendered against Alta Mesa or Meridian. In addition, Alta Mesa's ability to collect any amounts due pursuant to these indemnification obligations will depend upon the liquidity and solvency of HMI.

SEC Investigation

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The SEC is conducting a formal investigation into, among other things, the facts involved in the material weakness in our internal controls over financial reporting and the impairment charge disclosed elsewhere in our financial statements. We are cooperating with this investigation. At this point we are unable to predict the timing or outcome of this investigation. If the SEC determines that violations of the federal securities laws have occurred, the agency has a broad range of civil penalties and other remedies available, some of which, if imposed on us, could be material to our business, financial condition or results of operations.

Environmental Claims

Various landowners have sued Alta Mesa in lawsuits concerning several fields in which Alta Mesa's subsidiaries have, or historically had, operations. The lawsuits seek injunctive relief and other relief, including unspecified amounts in both actual and punitive damages for alleged breaches of mineral leases and alleged failure to restore the plaintiffs' lands from alleged contamination and otherwise from its oil and gas operations. We are unable to express an opinion with respect to the likelihood of an unfavorable outcome of the various environmental claims or to estimate the amount or range of potential loss should the outcome be unfavorable. Therefore, we have not provided any material amounts for these claims in our consolidated financial statements at December 31, 2018.

Item 4. Mine Safety Disclosures

Not applicable.

PART II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters, and Issuer Purchases of Equity Securities

(a) Market Information

Our Class A Common Stock and Public Warrants are currently listed on NASDAQ under the symbols "AMR" and "AMRWW," respectively.

Our Class C Common Stock does not trade on any market however, holders of our Class C Common Stock hold an equal number of SRII Opco Common Units that were issued upon the closing of the Business Combination. Holders of Class C Common Stock have the right to cause SRII Opco to redeem all or a portion of their SRII Opco Common Units in exchange for an equal number of shares of our Class A Common Stock or, at SRII Opco's option, an equivalent amount of cash. Upon such an exchange, a corresponding number of shares of Class C Common Stock would be canceled.

(b) Holders

As of June 28, 2019, there were 17 holders of record of our Class A Common Stock, 10 holders of record of our Class C Common Stock and 6 holders of record of our Public Warrants. The number of record holders of our Class A Common Stock and Public Warrants does not include DTC participants or beneficial owners holding shares of Public Warrants through nominee names.

(c) Dividends

We have not paid any cash dividends on our Class A Common Stock to date. The payment of any cash dividends on our Class A Common Stock is within the discretion of our Board of Directors (the "Board") but, our ability to declare dividends is generally prohibited by our debt agreements. Holders of our Class C Common Stock are not entitled to dividends at any time.

(d) Securities Authorized for Issuance Under Equity Compensation Plans

Information required by this section is in Part III, Item 12.

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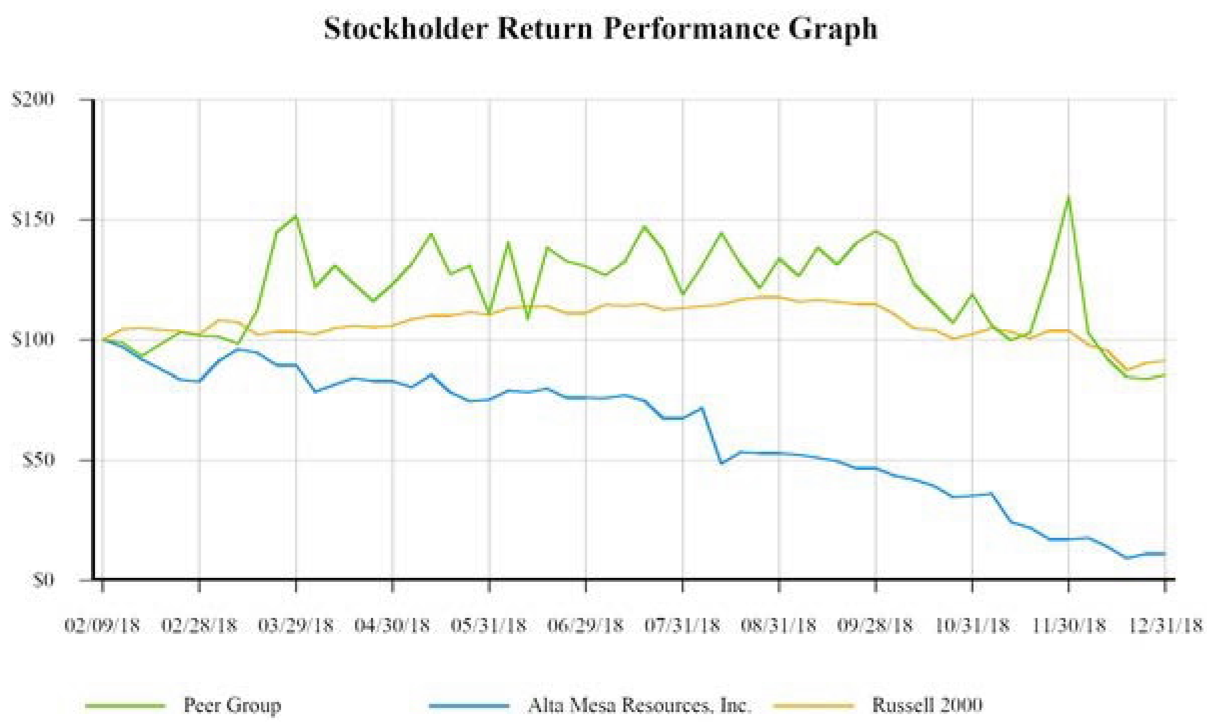
(e) Performance Graph

We do not consider the following information to be "soliciting material" or to be "filed" with the SEC, nor shall the information be incorporated by reference into any future filing under the Securities Act or the Exchange Act, except as specified by us.

The following graph compares the total return to stockholders of AMR's common stock relative to the cumulative total returns of the Russell 2000 index and a selected peer group of twelve companies during the Successor Period. We had no material operations prior to February 9, 2018. Assets prior to February 9, 2018 consisted primarily of proceeds held in a Trust Account from the Company's initial public offering completed on March 29, 2017, pending use of those funds for completion of a business combination.

An investment of $100 (with reinvestment of all dividends) is assumed to have been made in our common stock, in the Russell 2000 index and in each company's stock in our peer group on February 9, 2018, with the relative weighted average performance of each tracked through December 31, 2018. The returns shown are not intended to suggest future performance. The companies included in the selected peer group are:

EOG Resources, Inc.	Range Resources Corporation
Marathon Oil Corporation	Whiting Petroleum Corporation
Pioneer Natural Resources Company	Newfield Exploration Company
Noble Energy, Inc.	Diamondback Energy, Inc.
Continental Resources, Inc.	Approach Resources, Inc.
Concho Resources Inc.	Midstates Petroleum Company, Inc.



(f) Recent Sales of Unregistered Securities

None.

(g) Purchases of Equity Securities by the Issuer and Affiliated Purchasers

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In August 2018, our Board authorized the repurchase of up to $50.0 million of the Company's outstanding Class A Common Stock, exclusive of any fees, commissions or other expenses related to such repurchases. Repurchases could be made at the Company's discretion in accordance with applicable securities laws from time to time in open market or private transactions. All shares repurchased will be retired. The authorization has no expiration date.

The following table presents information about repurchases and retirements of our common stock for the quarter ended December 31, 2018:

Period	(a) Total number of shares purchased [(1)]	(b) Average price paid per share [(1)]	(c) Total number of shares purchased as part of a publicly announced plan [(2)]	(d) Maximum dollar amount of shares that may yet be purchased under the plan [(2)]
10/1/2018 to 10/31/2018	—	$ —	—	$ 35,281,244
11/1/2018 to 11/30/2018	—	$ —	—	$ 35,281,244
12/1/2018 to 12/31/2018	—	$ —	—	$ 35,281,244
Total	—	$ —	—	$ 35,281,244

(1) The Company did not purchase any shares of Class A Common Stock during the fourth quarter of 2018 under the share repurchase program approved by the Board. Information on shares repurchased from employees for personal income tax withholding on the vesting of restricted stock awards and performance-based restricted stock units is included in Part II, Item 8. During the latter part of the third quarter of 2018, we acquired 3,101,510 shares under this program at an average cost, including commissions, of $4.76 per share.

(2) On August 14, 2018, the Company announced a share repurchase program to purchase up to $50.0 million in shares of Class A Common Stock. The program does not have an expiration date.

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Item 6. Selected Financial Data

The following information has been derived from our audited consolidated financial statements.

?	Successor	Predecessor				
	February 9, 2018 Through December 31, 2018	January 1, 2018 Through February 8, 2018	Year Ended December 31,			
(in thousands)			2017 (1)	2016 (1)	2015 (1)	2014 (1)
Statement of Operations Information:						
Total operating revenue	$ 467,977	$ 47,639	$ 279,369	$ 101,899	$ 325,363	$ 213,907
Operating income (2)	(3,208,169)	(1,777)	36,670	(57,337)	162,697	80,949
Income (loss) from continuing operations (2)	(3,249,347)	(7,116)	(12,846)	(134,279)	101,584	25,197
Income (loss) from discontinued operations, net of tax (3)	—	(7,746)	(64,815)	(33,642)	(233,377)	74,179
Net income (loss)	(3,249,347)	(14,862)	(77,661)	(167,921)	(131,793)	99,200
Net loss attributable to non-controlling interest	(1,724,648)	—	—	—	—	—
Net loss attributable to Alta Mesa Resources, Inc. Stockholders	(1,524,699)	—	—	—	—	—
?						
Net loss per common share attributable to Alta Mesa Resources Inc. Stockholders:						
Basic	$ (8.71)	N/A	N/A	N/A	N/A	N/A
Diluted	$ (8.71)	N/A	N/A	N/A	N/A	N/A
Balance Sheet Information (at period end):						
Cash and cash equivalents	$ 26,854	$ 9,070	$ 3,721	$ 7,185	$ 8,869	$ 1,349
Total assets (4)	1,357,830	1,094,685	1,085,397	813,851	722,525	911,125
Total debt, including Founder Notes (5)	864,123	624,558	635,606	556,862	743,523	785,682
Total equity	216,127	183,065	154,445	32,106	(177,049)	(61,446)

(1) Our statement of operations information for prior years has been adjusted to reflect the disposal of non-STACK oil and gas assets as discontinued operations.

(2) The Successor Period includes total impairment charges of $3.2 billion for oil and gas properties, other property and equipment, intangible assets, goodwill and an equity method investment. Additionally, impairment charges on oil and gas properties of $1.2 million, $0.4 million and $18.8 million, were recognized during 2017, 2016 and 2015, respectively.

(3) For the period January 1, 2018 to February 8, 2018 and 2017, 2016, 2015, and 2014, income (loss) from discontinued operations, net of tax, includes $0.9 million, $24.5 million, $41.3 million, $82.7 million, and $112.7 million, respectively, of depreciation, depletion and amortization expense. For the period January 1, 2018 to February 8, 2018 and for 2017, 2016, 2015 and 2014, income (loss) from discontinued operations, net of tax, includes impairment charges on oil and gas properties of $5.6 million, $29.1 million, $15.9 million, $158.0 million and $74.9 million, respectively. Additionally, income (loss) from discontinued operations, net of tax, for 2014 includes an $87.5 million gain on the sale of oil and gas properties.

(4) Total assets include $49.0 million, $156.7 million, $203.3 million, and $499.9 million as of December 31, 2017, 2016, 2015, and 2014, respectively, related to non-STACK assets.

(5) Prior to the Business Combination, we had notes payable to our founder ("Founder Notes") which, at the Business Combination, were converted into an equity interest in the AM Contributor. The balance of the Founder Notes at the time of conversion was $28.3 million, including accrued interest.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis should be read in conjunction with the "Selected Financial Data" and the consolidated financial statements and related notes included elsewhere in this Annual Report. The following discussion and analysis contains forward-looking statements that reflect our future plans, estimates, beliefs and expected performance. The forward-looking statements are dependent upon events, risks and uncertainties that may be outside our control. Our actual results could differ materially from those discussed in these forward-looking statements. Factors that could cause or contribute to such differences include, but are not limited to, the volatility of oil and gas prices, production timing and volumes, our ability to continue as a going concern, estimates of proved reserves, operating costs and capital expenditures, economic and competitive conditions, regulatory changes and other uncertainties, as well as those factors discussed below and elsewhere in this Annual Report, particularly in "Item 1A. Risk Factors" and "Cautionary Statement Regarding Forward-Looking Statements," all of which are difficult to predict. As a result of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur.

Overview

Alta Mesa Resources, Inc., together with its consolidated subsidiaries ("we" or "the Company"), is an independent exploration and production company focused on the acquisition, development, exploration and exploitation of unconventional onshore oil and natural gas reserves in the eastern portion of the Anadarko Basin in Oklahoma. We operate in two reportable business segments - Upstream and Midstream. Alta Mesa Holdings, LP ("Alta Mesa") conducts our Upstream activities and owns our proved and unproved oil and gas properties located in an area of the Anadarko Basin commonly referred to as the STACK. We generate upstream revenue principally by the production and sale of oil, gas and NGLs. We also operate in the Midstream segment through Kingfisher Midstream, LLC ("KFM"). KFM has a gas and oil gathering network, a cryogenic gas processing plant with offtake capacity, field compression facilities and a produced water disposal system in the Anadarko Basin that generate revenue primarily through long-term, fee-based contracts. The KFM assets are integral to our Upstream operations, which we conduct in the same region, and they are strategically positioned to provide similar services to other producers in the area.

As of December 31, 2018, we have a highly contiguous position of 140,400 net acres in the up-dip, naturally-fractured oil portion of the STACK primarily in eastern Kingfisher and southeastern Major Counties in Oklahoma. Our drilling locations primarily target the Osage, Meramec and Oswego formations. After the Business Combination, we conducted development activities using a spacing array of 6 to 10 wells per section and running up to 9 rigs at the peak activity level. In late 2018, our production across the acreage evidenced that the well spacing was not delivering the well level production that we expected. During January 2019, we suspended our development program to allow our new management team to conduct a full operational and economic review. We restarted our development program in March 2019 with a less dense spacing pattern of up to five wells per section. In addition, we have worked to improve our economic returns by reducing well costs, general and administrative expense and other operating expense. We have operated 2 rigs since restarting the program, however following the redetermination of the borrowing base of the Alta Mesa RBL in August 2019, we have decided to operate 1 rig starting in September. We will continue to evaluate how much, if any, development is appropriate going forward.

Additional information relating to the formation of the Company and the acquisition of Alta Mesa and KFM on February 9, 2018, may be found in Item 8. Immediately prior to the Business Combination, Alta Mesa distributed its non-STACK oil and gas assets and related liabilities to High Mesa Holdings, LP (the "AM Contributor"). We have reported these distributed assets as discontinued operations for all periods presented.

Pursuant to the Business Combination, we recorded the acquired assets and liabilities at their estimated fair values on the closing date, including recording the fair values in the financial records of our respective subsidiaries. This resulted in our financial presentation being separated into two distinct periods, the period before the Business Combination ("Predecessor Period") and the period after the Business Combination ("Successor Period"). The Company's financial statement presentation reflects Alta Mesa as the "Predecessor" for periods prior to February 9, 2018. The Company, including the consolidated results of Alta Mesa and Kingfisher, is the "Successor" for periods since February 9, 2018.

Accordingly, for purposes of explaining our segment results, we have presented the Successor Period and the 2018 Predecessor Period results of Alta Mesa, our Upstream segment, in comparison to Alta Mesa's results of operations for 2017 and we have presented the Upstream segment's results for 2017 in comparison to 2016. As KFM, our Midstream segment, was acquired on February 9, 2018, our discussion of our Midstream segment results covers only the Successor Period.

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Outlook, Market Conditions and Commodity Prices

Our revenue, profitability and future growth rate depend on many factors, particularly the prices of oil, gas and NGLs, which are beyond our control. The success of our business is significantly affected by the price of oil due to its weighting in our production profile.

Factors affecting oil prices include worldwide economic conditions; geopolitical activities in various regions of the world; worldwide supply and demand conditions; weather conditions; actions taken by the Organization of Petroleum Exporting Countries; and the value of the U.S. dollar in international currency markets. Commodity prices remain unpredictable and it is uncertain whether the increase in market prices experienced during the first half of 2019 will be sustained. As a result, we cannot accurately predict future commodity prices and, therefore, cannot determine with any degree of certainty what effect increases or decreases in these prices will have on our capital expenditures, production volumes or revenue. In the event that oil, gas and NGLs prices significantly decrease, such decreases could have a material adverse effect on our financial condition, the carrying value of our oil and natural gas properties, our proved reserves and our ability to finance operations, including the amount of the borrowing capacity under the Alta Mesa RBL.

Going concern

Our present level of indebtedness and the current commodity price environment present challenges to our ability to comply with the covenants in the agreements governing our indebtedness. As a result of the decrease in our forecasted production levels compared to the forecasts at the time of the Business Combination and pressures created by lower commodity prices, in the absence of one or more deleveraging transactions, we do not anticipate maintaining compliance with the consolidated total leverage ratio covenant in the Alta Mesa RBL as early as the measurement date of September 30, 2019. In addition, we have been substantially fully utilized under the Alta Mesa RBL since April 2019 and have no meaningful remaining capital availability. Our lenders exercised their right to conduct an optional redetermination ahead of the regularly scheduled redetermination in October 2019 and have established a new borrowing base of $200.0 million, effective August 13, 2019.As provided under the Alta Mesa RBL, we have elected to repay the excess utilization in 5 equal monthly installments of $32.5 million, the first of which will be due in September 2019. If we are unable to make these deficiency payments, we would be in default under the Alta Mesa RBL.Our Board and its financial advisors are evaluating the available financial alternatives, including seeking amendments or waivers to the covenants or other provisions of our indebtedness to address our capital structure including raising new capital from the private or public markets or taking other actions either in court or out of court. If we are unable to reach an agreement with our lenders or find acceptable alternative financing, it may lead to an event of default under our debt agreements. If following an event of default, the Alta Mesa RBL lenders were to accelerate repayment, it may result in an event of default and an acceleration of the 2024 Notes. We have concluded that these circumstances create substantial doubt regarding our ability to continue as a going concern.

If an agreement is reached with our creditors and we pursue a restructuring, it may be necessary for us, or our subsidiaries, to file a voluntary petition for relief under Chapter 11 of the U.S. Bankruptcy Code in order to implement the agreement through the confirmation and consummation of a plan of reorganization approved by the bankruptcy court. We may also conclude it is necessary to initiate Chapter 11 proceedings to implement a restructuring of our obligations even if we are otherwise unable to reach an agreement with our creditors.If a plan of reorganization is implemented in a bankruptcy proceeding, it is possible that holders of claims and interests with respect to, or rights to acquire, our equity securities would be entitled to little or no recovery, and those claims and interests may be canceled for little or no consideration.If that were to occur, we anticipate that all or substantially all of the value of all investments in our equity securities would be lost and that our equity holders would lose all or substantially all of their investment. It is also possible that our stakeholders, including our secured and unsecured creditors, will receive substantially less than the amount of their claims. For a more detailed discussion, please read the Risk Factors in Item 1A.

Derivatives

The objective of our hedging program is to produce, over time, relative revenue stability. However, in the short term, both settlements and fair value changes in our derivatives can significantly impact our results of operations, and we expect these gains and losses to continue to reflect the impact of changes in oil and gas prices. Our derivatives are reported at fair value and are sensitive to changes in the price of oil and gas. Changes in derivatives are reported as gain (loss) on derivatives, which include both the unrealized increase and decrease in their fair value, as well as the effect of realized settlements during the period. For the Successor Period, we recognized a net loss on our derivatives of$10.2 million, which includes $39.0 million in

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cash settlements paid for derivatives. Our Alta Mesa RBL generally has minimum and maximum hedging limits as further described elsewhere.

Impairments

In late fourth quarter of 2018, the combination of depressed prevailing oil and gas prices, changes to assumed spacing in conjunction with evolving views on the viability of multiple benches and reduced individual well expectations resulted in impairment charges of $2.0 billion to our proved and unproved oil and gas properties. Individual well expectations were impacted by reductions in estimated reserve recovery of original oil and gas in place. At the time of the Business Combination, we believed that the stratigraphy underlying our acreage was conducive to development of three distinct benches within the broader Mississippian section. Proved reserve assumptions at the time of the Business Combination were based on initial wells drilled in the STACK, stated expectations from other operators in the STACK as well as analogous results from other resource plays.These proved reserve assumptions included spacing of four wells per section and probable and possible resource assumptions included an incremental three wells per section for a total of seven wells per section. An incremental five wells per section (for a total of 12 wells per section) were classified as contingent resources to which no value was assigned in the purchase price allocation for the Business Combination.We expected all proved and unproved wells to deliver similar results of approximately 250 Mbbl of reserve recovery.Our 2018 drilling program was executed under these assumptions and by early 2019, we had 17 different sectional development patterns with six to ten wells per section and meaningful production results. The pattern wells generally produced as expected for the initial 60 days but began to fall below type curve after 90-120 days, which we believe was due to interference associated with the current spacing and benches. Our analysis of these results led to the following individual well reserve recovery and the overall spacing assumptions (all arrived at prior to the de-recognition of PUDs more fully described elsewhere):

- No distinct benches exist within the Mississippian section that are not in direct communication with each other resulting in only four to five wells per section that we believe should be spaced horizontally 1,000 feet or more apart;
- Year-end PUD type curves for future development are estimated to have reserves of 175 Mbbl per well, down from the 250 Mbbl at the time of the Business Combination;
- Year-end proved reserve spacing per section is assumed at four or five wells per section which is roughly equivalent to the assumptions at the time of the Business Combination;
- Year-end probable and possible resource individual well recovery was assessed to be 200 Mbbl compared to 250 Mbbl at the time of the Business Combination;
- Year-end probable and possible resource spacing assumes no additional wells per section on fully developed proved sections; and
- No incremental recovery expected from contingent resources.

In May 2018, a subsidiary of KFM entered into agreements with a third party to jointly construct and operate a new crude oil pipeline via creation of Cimarron that we accounted for under the equity method. Cimarron's proposed pipeline was to extend from our processing plant to Cushing, Oklahoma and was to be constructed and operated by Cimarron, which we determined was controlled by the non-KFM owner.

As the outlook for Alta Mesa volumes and third-party volume opportunities in the area were significantly lower than initially projected, we suspended future contributions to Cimarron and have begun discussions to abandon the project.We do not believe the project will be completed and we conducted an impairment analysis resulting in the recognition of an impairment charge of$16.0 million during the Successor Period to reduce the carrying value of our investment in Cimarron to its estimated fair value atDecember 31, 2018.

Based on an estimation of the fair value of KFM utilizing an income approach that took into consideration the outlook for Alta Mesa and third-party volumes available for processing, we determined that a portion of the value of KFM's plant and equipment and all of KFM's intangible assets and goodwill were impaired at December 31, 2018.

The summary of impairment expense follows:

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(in millions)	Successor February 9, 2018 Through December 31, 2018	Predecessor January 1, 2018 Through February 8, 2018	Predecessor Year Ended December 31, 2017	Predecessor Year Ended December 31, 2016
Impairment attributable to:				
Upstream				
Unproved properties	$ 742.1	$ —	$ —	$ —
Proved properties	1,291.6	—	1.2	0.4
Total Upstream	2,033.7	—	1.2	0.4
Midstream				
Investment in Cimarron	16.0			
Property, plant and equipment	68.4			
Intangible assets	395.0	—	—	—
Goodwill	692.0	—	—	—
Total Midstream	1,171.4	—	—	—
Total impairment of assets	$ 3,205.1	$ —	$ 1.2	$ 0.4

Factors affecting future performance and our outlook

The primary factors affecting our production levels, which may be interrelated,are current commodity prices, capital availability, the effectiveness and efficiency of our production operations, the success of our drilling program and our inventory of drilling prospects. In addition, our wells have significant natural production declines. We attempt to overcome this natural decline primarily through development of our existing undeveloped resource, well recompletions and other enhanced recovery methods. Sustaining our production levels or our future growth will depend on our ability to continue to develop reserves. Our ability to add reserves through drilling and other development techniques is dependent on current market conditions and our capital resources and can be limited by many factors, including our ability to timely obtain drilling permits and regulatory approvals. Any delays in drilling, completing or connecting our new wells to gathering lines will negatively affect our production, which will have an adverse effect on our revenue and, as a result, our cash flow from operations.

Results of Operations

Business Segments

Our discussion of results of operations is presented on a segment basis. Our two reportable segments are (1) Upstream and (2) Midstream, which separately feature distinct revenue producing activities. We evaluate Upstream and Midstream segment performance using Adjusted EBITDAX and Adjusted EBITDA, respectively.

The Company's management believes Adjusted EBITDAX and Adjusted EBITDA are useful because they allow users to more effectively evaluate our operating performance, compare the results of our operations from period to period and against our peers without regard to our financing methods or capital structure and because it highlights trends in our business that may not otherwise be apparent when relying solely on GAAP measures. Adjusted EBITDAX and Adjusted EBITDA should not be considered as an alternative to our segments' net income (loss), operating income (loss) or other performance measures derived in accordance with GAAP and may not be comparable to similarly titled measures in other companies' reports. The Company's applicable corporate activities have also been allocated to the supported business segments.

For the Periods from February 9, 2018 Through December 31, 2018 (Successor) and January 1, 2018 Through February 8, 2018 (Predecessor) Compared to the Year Ended December 31, 2017 (Predecessor)

The segment results exclude financial information related to discontinued operations and exclude inter-segment consolidating eliminations.

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Upstream Segment Results of Operations

Our Upstream segment was impacted by the Business Combination, which caused our 2018 results to be separately presented between Successor and Predecessor Periods. In preparing the following discussion, we have provided a combined total to arrive at a full year 2018 amount and context for the change of such full year amount to the 2017 comparable amount. We view 2018 as a single reporting period since the impact of the Business Combination was limited to the items described below. We believe that this approach:

- allows readers of our financial statements to see how management has evaluated the operating results;
- provides readers of our financial statements with adequate context for their analysis of our operating results; and
- provides a better context for whether past results are indicative of future results.

The impact to our Upstream results following the Business Combination primarily relates to increased depletion expense associated with a step-up for proved oil and gas properties and to impairment expense which is associated with the step-up for both unproved and proved oil and gas properties. We do not believe that the presentation of full pro forma segment results is more preferable than the information that follows.

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Revenue

Our oil, gas and NGLs revenue varies as a result of changes in commodity prices and production volumes. The following table summarizes our revenue and production data for the periods presented:

?	Successor	Predecessor	
(in thousands, except per unit data)?	**February 9, 2018 Through December 31, 2018**	**January 1, 2018 Through February 8, 2018**	**Year Ended December 31, 2017**
Net production:			
Oil (Mbbl)	5,053	494	3,907
Natural gas (MMcf)	16,913	1,609	13,972
NGLs (Mbbl)	2,268	151	1,277
Total (MBoe)	10,140	914	7,513
?			
Average net daily production volume:			
Oil (Mbbld)	15.4	12.7	10.7
Natural gas (MMcfd)	51.9	41.2	38.3
NGLs (Mbbld)	7.0	3.9	3.5
Total (MBoed)	31.1	23.4	20.6
?			
Average sales prices:			
Oil (per bbl)	$ 63.99	$ 62.68	$ 49.76
Effect of realized derivatives settlements (per bbl)	(7.35)	(6.44)	(0.34)
Oil, after hedging (per bbl)	$ 56.64	$ 56.24	$ 49.42
Percentage of unhedged realized oil price to NYMEX oil price	99%	99%	98%
?			
Natural gas (per Mcf)	$ 2.57	$ 2.66	$ 2.70
Effect of realized derivatives settlements (per Mcf)	(0.15)	0.94	0.49
Natural gas, after hedging (per Mcf)	$ 2.42	$ 3.60	$ 3.19
Percentage of unhedged realized gas price to NYMEX gas price	84%	87%	89%
?			
NGLs (per bbl)	$ 18.98	$ 26.41	$ 24.62
Effect of realized derivatives settlements (per bbl)	—	—	(1.14)
NGLs, after hedging (per bbl)	$ 18.98	$ 26.41	$ 23.48
Percentage of unhedged NGL price to NYMEX oil price	29%	42%	48%
Revenue			
Oil sales	$ 323,299	$ 30,972	$ 194,423
Natural gas sales	43,407	4,276	37,794
NGL sales	43,039	4,000	31,445
Total Upstream sales revenue	$ 409,745	$ 39,248	$ 263,662

Oil revenue for the Successor Period and the 2018 Predecessor Period increased compared to the year ended December 31, 2017 due to an increase in production in 2018 and higher average market prices. The increase in production in 2018 was due to an increase in the number of wells drilled and new wells on production as a consequence of a sharp increase in 2018 capital expenditures.

Natural gas revenue for the Successor Period and the 2018 Predecessor Period increased compared to the year ended December 31, 2017, due to an

increase in production in 2018, which was partially offset by lower average market prices.

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NGL revenue for the Successor Period and the 2018 Predecessor Period increased compared to the year ended December 31, 2017 due to an increase in production in 2018, partially offset by lower average prices. The increase in production volume was primarily due to our 2018 development activities. The pricing reduction primarily relates to the volume election, as described below. Under our gathering contract with KFM, we have an ability to determine ethane recovery volumes as either actual volumes or as the levels that the plant can recover.In 2018, we generally elected to recover ethane volumes, which had the impact of increasing the NGLs volume and decreasing the price received per barrel.

Gain (loss) on sale of assets in 2018 primarily includes a gain for the sale of seismic data totaling $5.1 million in the Successor Period.

Gain on acquisition of oil and gas properties in 2017 was related to a bargain purchase of certain proved STACK oil and gas reserves resulting in a gain totaling $1.7 million in 2017. A bargain purchase occurs when the fair value of the assets acquired, net of the fair value of liabilities assumed, exceeds the purchase price paid.

	Successor	Predecessor	
(in thousands)?	**February 9, 2018 Through December 31, 2018**	**January 1, 2018 Through February 8, 2018**	**Year Ended December 31, 2017**
Gain (loss) on derivatives:			
Realized gains (losses) -			
Oil	$ (36,505)	$ (3,819)	$ (1,325)
Natural gas	(2,456)	1,523	6,904
NGLs	—	—	(1,462)
Total realized gains (losses)	(38,961)	(2,296)	4,117
Unrealized gains (losses)	28,714	8,959	4,170
Total gain (loss) on derivatives	$ (10,247)	$ 6,663	$ 8,287

Gain (loss) on derivatives changes represent market movements in futures prices compared with the levels where our ongoing hedging program are struck. Unrealized gains in the Successor Period were substantially influenced by the spot and futures price declines during the latter half of 2018, particularly during in the last week of December 2018.

Operating Expenses

?	Successor	Predecessor	
(in thousands, except per unit data)?	February 9, 2018 Through December 31, 2018	January 1, 2018 Through February 8, 2018	Year Ended December 31, 2017
Operating expenses:			
Lease operating	$ 60,547	$ 4,408	$ 43,953
Transportation and marketing	50,038	3,725	29,460
Production taxes	16,865	953	5,494
Workovers	5,563	423	4,255
Exploration	34,085	7,003	13,563
Depreciation, depletion and amortization	133,554	11,670	89,115
Impairment of assets	2,033,712	—	1,188
General and administrative	114,735	21,234	55,671
Total Upstream operating expense	$ 2,449,099	$ 49,416	$ 242,699
?			
Select operating expenses per BOE:			
Lease operating	$ 5.97	$ 4.82	$ 5.85
Transportation and marketing	4.93	4.08	3.92
Production taxes	1.66	1.04	0.73
Workovers	0.55	0.46	0.57
Depreciation, depletion and amortization	13.17	12.77	11.86

Lease operating expense for the Successor Period and the 2018 Predecessor Period increased compared to 2017, primarily due to cost associated with increased use of submersible pumps for artificial lift, and increased costs associated with our produced water disposal assets (prior to their sale to KFM) and additional wells drilled.

Transportation and marketing expense in the Predecessor Periods represents throughput for our properties in the STACK at the KFM processing facility. Transportation and marketing expense in the Successor Period and the 2018 Predecessor Period increased compared to the year ended December 31, 2017, primarily due to higher volumes flowing from our operated wells into the KFM plant. The fee we pay per unit reflects the firm processing capacity at the plant, as well as firm transport for our residue gas at the tailgate of the plant.

Production taxes for the Successor Period and 2018 Predecessor Period are higher as compared to 2017 primarily due to the increase in oil and natural gas liquids revenue and an increase in the Oklahoma severance tax rate from 2% to 5%, effective in the third quarter of 2018, for wells in their first 3 years of production. Production taxes are assessed based on revenues on a pre-hedge basis.

?	Successor	Predecessor	
(in thousands)?	February 9, 2018 Through December 31, 2018	January 1, 2018 Through February 8, 2018	Year Ended December 31, 2017
Exploration expense:			
Geological and geophysical costs	$ 6,755	$ 2,440	$ 5,729
Exploratory dry hole expense	1,954	—	—
Other exploration expense, including expired leases	24,374	4,504	7,797
ARO settlements in excess of recorded liabilities	1,002	59	37
Total exploration expense	$ 34,085	$ 7,003	$ 13,563

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Exploration expense for the Successor Period and the 2018 Predecessor Period increased compared to 2017 primarily due to an increase in expired leaseholds of $20.1 million and a single exploratory dry hole costing $2.0 million.

Depreciation, depletion and amortization expense was higher on a per BOE basis in the Successor Period and the 2018 Predecessor Period as compared to 2017, primarily due to an increase in capital spending and in production in relation to booked reserves for 2018 on a Boe basis.

?	Successor	Predecessor	
(in thousands)?	**February 9, 2018 Through December 31, 2018**	**January 1, 2018 Through February 8, 2018**	**Year Ended December 31, 2017**
Impairment of assets:			
Impairment of unproved properties	$ 742,065	$ —	$ —
Impairment of proved properties	1,291,647	—	1,188
Total impairment of assets	$ 2,033,712	$ —	$ 1,188

Impairment of assets largely hinges on a decrease in commodity prices, as well as the results of exploratory and development drilling and well performance, which reduced the value of our assets. A significant decline in spot and future estimated commodity prices late in the fourth quarter of 2018, and the impact of changes in our individual well reserve recovery estimates triggered a downward revision in the future cash flows expected to be generated by our oil and gas properties, which required us to reduce the carrying value of those properties to estimated fair value.

?	Successor	Predecessor	
(in thousands)?	**February 9, 2018 Through December 31, 2018**	**January 1, 2018 Through February 8, 2018**	**Year Ended December 31, 2017**
General and administrative expense:			
Employee-related costs	$ 20,129	$ 1,032	$ 28,317
Strategic costs - Business Combination costs	23,717	17,040	8,118
Equity-based compensation	20,000	—	—
Professional fees	13,028	1,019	10,567
Severance costs	8,357	—	—
Provision for uncollectible related party receivables	22,438	—	—
Other	7,066	2,143	8,669
Total general and administrative expense	$ 114,735	$ 21,234	$ 55,671

General and administrative expense for the Successor Period and the 2018 Predecessor Period increased compared to 2017.Strategic costs and professional fees were higher in 2018 due to advisors helping to value and integrate the acquired business pursuant to the Business Combination, plus the related increase in accounting and audit professional fees. The Successor Period also includes a $22.4 million reserve associated with estimated collectibility of receivables from certain related parties (including notes receivable), equity-based compensation awards and the establishment of a stock-based compensation program, plus severance costs associated with the departure of certain members of executive management in late 2018, with no similar activity in the Predecessor Periods. Employee-related costs decreased primarily due to reduced headcount.

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Below is a reconciliation of Upstream Adjusted EBITDAX to loss from continuing operations before income taxes:

	Successor	Predecessor	
(in thousands)	February 9, 2018 Through December 31, 2018	January 1, 2018 Through February 8, 2018	Year Ended December 31, 2017
Loss from continuing operations before income taxes	$ (2,076,370)	$ (7,116)	$ (12,840)
Interest expense	38,265	5,511	50,585
Gain on unrealized hedges	(28,714)	(8,959)	(4,170)
Loss on sale of property and equipment	388	—	—
Exploration	34,085	7,003	13,563
Depreciation, depletion and amortization	133,554	11,670	89,115
Impairment of assets	2,033,712	—	1,188
Provision for uncollectible related party receivables(1)	22,438	—	—
Equity-based compensation	20,000	—	—
Business Combination related expense	23,717	17,040	8,118
Upstream Adjusted EBITDAX	$ 201,075	$ 25,149	$ 145,559

(1) Represents a reserve associated with estimated collectibility of certain related party receivables (including notes receivable) and is included in general and administrative expense in the Successor Period.

Midstream Segment Results of Operations

Revenue

Our Midstream revenue was primarily derived from product sales, gas gathering and processing, crude oil gathering, and produced water gathering and disposal fees.

?

	Successor
(in thousands)	February 9, 2018 Through December 31, 2018
Sales of gathered production	$ 31,506
Midstream revenue	68,519
Total Midstream sales revenue	$ 100,025
KFM gas volumes (MMcf)	35,058
KFM crude oil gas volumes (Mbbls)	1,739
KFM produced water gathering volumes (Mbbls)	5,320

Sales of gathered production were recognized from the sale of processed residue gas, condensate and NGLs. We process the gas on behalf of the producer and sell the resulting gas, condensate and NGLs at a market price. We remit to the producer an agreed-upon price from the resulting sales, which is treated as product expense. The product sales are recognized when sold to the third-party purchaser. Amounts recognized in product sales are dependent on whether we are acting in the role of a principal or agent in our contracts with our customers.

Midstream revenue was driven by gas volumes gathered and processed, produced water gathered and disposed, and crude oil volumes gathered under our commercial agreements and the fees assessed for such services. The throughput of gas gathered and processed, crude oil gathered, and produced water gathered and disposed is derived from the level of drilling and well completion activity of our customers.

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Expenses

?	Successor
(in thousands)	**February 9, 2018 Through December 31, 2018**
Midstream operating	$ 15,221
Cost of sales for purchased gathered production	31,247
Transportation and processing	9,911
Depreciation, depletion and amortization	27,388
Impairment of assets:	
Impairment of Cimarron investment	15,963
Impairment of property, plant and equipment	68,407
Impairment of intangible assets	394,999
Impairment of goodwill	691,970
Total Midstream impairment of assets	1,171,339
General and administrative	14,025
Total operating expenses	$ 1,269,131

Midstream operating expense represents expenses incurred to operate the gas gathering and processing facilities and the crude oil gathering and storage facilities and produced water gathering and disposal facilities, which primarily includes company labor and equipment rentals and maintenance, and expenses related to the produced water assets sold from the Upstream segment to the Midstream segment in November 2018.

Cost of sales for purchased gathered production represents payments to producers for their agreed-upon percent of proceeds from the sale of processed gas, condensate and NGLs.

Transportation and processing expense includes compression, gathering, processing and deficiency fees for third-party offtakes, along with fees for unutilized firm transport capacity.

Depreciation, depletion and amortization expense includes depreciation on the midstream facilities, gathering system and produced water assets acquired in November 2018 and amortization of customer contracts and relationships.

Impairment of assets includes impairment charges of $68.4 million to write-down certain property and equipment, as well as $395.0 million and $699.9 million to write-off the carrying amount of intangible assets and goodwill, respectively, during the Successor Period. The fair value of the Midstream segment was negatively impacted by a significant decline in commodity prices in the fourth quarter of 2018 and the related impact on our and other producers' future upstream operating plans. Our upstream operations contribute a significant portion of the volumetric throughput to the KFM plant. A decline in such throughput negatively impacts future expected profitability, and thus, fair value of the Midstream segment. Additionally, we reduced the carrying amount of our investment in Cimarron by $16.0 million to adjust its carrying value to fair value at December 31, 2018 as we believe completion of this project is not probable based on current transportation needs.

?	Successor
(in thousands)	**February 9, 2018 Through December 31, 2018**
General and administrative expenses:	
Employee-related costs	$ 8,199
Equity-based compensation	1,190
Professional fees	1,566
Other	3,070
Total general and administrative expense	$ 14,025

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Below is a reconciliation of Midstream EBITDA to loss from continuing operations before income taxes:

(in thousands)	Successor February 9, 2018 Through December 31, 2018
Loss from continuing operations before income taxes	(1,174,131)
Interest expense	5,031
Depreciation, depletion and amortization	27,388
Impairment of assets	1,171,339
Equity-based compensation	1,190
Midstream EBITDA	$ 30,817

Consolidated Results of Operations

Other Income (Expense)

?	Successor	Predecessor	
(in thousands)?	February 9, 2018 Through December 31, 2018	January 1, 2018 Through February 8, 2018	Year Ended December 31, 2017
Alta Mesa RBL	$ 2,807	$ 815	$ —
Alta Mesa Predecessor Credit Facility	—	—	7,283
KFM Credit Facility	5,031	—	—
2024 Notes	35,273	3,281	39,375
Bond premium amortization	(4,512)	—	—
Deferred financing cost amortization	221	170	2,732
Other	4,476	1,245	1,195
Total interest expense	43,296	5,511	50,585
Interest income and other	(2,049)	(172)	(1,075)
Total other (income) expense	$ 41,247	$ 5,339	$ 49,510

Interest expense for the Successor Period and 2018 Predecessor Period decreased primarily due to amortization of bond premium of $4.5 million and lower interest on the Alta Mesa RBL due to lower average amounts outstanding as compared to the Alta Mesa Predecessor Credit Facility.

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For the Year Ended December 31, 2017 Compared to the Year Ended December 31, 2016

The tables included below set forth financial information of our Predecessor for the years ended December 31, 2017 and 2016. The amounts below exclude operating results related to discontinued operations.

Upstream Segment Results of Operations

Revenue

Our oil, gas and NGLs revenue varies as a result of changes in commodity prices and production volumes. The following table summarizes our upstream revenue and for the periods presented:

?	Predecessor	
(in thousands, except per unit data)	**Year Ended December 31, 2017**	**Year Ended December 31, 2016**
Net production:		
Oil (Mbbl)	3,907	2,571
Natural gas (MMcf)	13,972	8,259
NGLs (Mbbl)	1,277	824
Total (MBoe)	7,513	4,772
?		
Average net daily production volume:		
Oil (Mbbld)	10.7	7.0
Natural gas (MMcfd)	38.3	22.6
NGLs (Mbbld)	3.5	2.3
Total (MBoed)	20.6	13.1
?		
Average sales prices:		
Oil (per bbl)	$ 49.76	$ 41.15
Effect of realized derivatives settlements (per bbl)	(0.34)	32.10
Oil, after hedging (per bbl)	$ 49.42	$ 73.25
Percentage of unhedged realized oil price to NYMEX oil price	98%	95%
?		
Natural gas (per Mcf)	$ 2.70	$ 2.42
Effect of derivatives settlements (per Mcf)	0.49	0.79
Natural gas, after hedging (per Mcf)	$ 3.19	$ 3.21
Percentage of unhedged realized gas price to NYMEX gas price	89%	95%
?		
NGLs (per bbl)	$ 24.62	$ 17.21
Effect of derivatives settlements (per bbl)	(1.14)	(0.40)
NGLs, after hedging (per bbl)	$ 23.48	$ 16.81
Percentage of unhedged realized NGL price to NYMEX oil price	48%	40%
Revenue		
Oil sales	$ 194,423	$ 105,811
Natural gas sales	37,794	20,021
NGL sales	31,445	14,174
Total Upstream sales revenue	$ 263,662	$ 140,006

The 2017 increase in oil revenue was primarily attributable to higher average sales prices pre-hedge as well as increased production volumes. An increase in production of 1,336 Mbbls, resulted in an approximate $55.0 million increase in oil revenue at 2016 average oil sales price. The increase in oil volumes is primarily due to new production.

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The 2017 increase in natural gas revenue was attributable to increased production volumes as well as higher prices during 2017. The increase in gas volumes is attributable to new production.

The 2017 increase in NGL revenue was primarily attributable to an increase in prices as well as increased volumes. The increase in natural gas liquid volumes is due primarily to an increase in output.

Gain on acquisition of oil and gas properties was related to a bargain purchase of certain proved STACK oil and gas reserves resulting in a gain totaling $1.7 million in 2017.

	Predecessor	
(in thousands)	**Year Ended December 31, 2017**	**Year Ended December 31, 2016**
Gain (loss) on derivatives:		
Realized gains (losses) -		
Oil	$ (1,325)	$ 82,522
Natural gas	6,904	6,500
NGLs	(1,462)	(333)
Total realized gains (losses)	4,117	88,689
Unrealized gains (losses)	4,170	(129,149)
Total gain (loss) on derivatives	$ 8,287	$ (40,460)

Operating Expenses

?

	Predecessor	
(in thousands, except per unit data)	**Year Ended December 31, 2017**	**Year Ended December 31, 2016**
Operating expenses:		
Lease operating	$ 43,953	$ 29,567
Transportation and marketing	29,460	11,628
Production taxes	5,494	2,765
Workovers	4,255	3,441
Exploration	13,563	17,230
Depreciation, depletion and amortization	89,115	53,755
Impairment of assets	1,188	382
General and administrative expenses	55,671	40,468
Total Upstream operating expense	$ 242,699	$ 159,236
Select operating expenses per BOE:		
Lease operating	$ 5.85	$ 6.20
Transportation and marketing	3.92	2.44
Production taxes	0.73	0.58
Workovers	0.57	0.72
Depreciation, depletion and amortization	11.86	11.26

Lease operating expense increased primarily due to increased production volume and increased compression, produced water disposal, chemicals, repairs and maintenance and fuel and power totaling $12.9 million.

Transportation and marketing expense increased primarily due to increased throughput at the KFM processing facility beginning in the second quarter of 2016. In addition, the increase is due to higher transportation and marketing fees charged to provide effective gathering, efficient processing and assurance that our production will continue to flow as the activity in the basin expands at the KFM processing facility.

Production taxes increased $3.0 million primarily due to the increase in oil and gas revenue. Ad valorem taxes remained flat year over year.

?	Predecessor	
(in thousands)	**Year Ended December 31, 2017**	**Year Ended December 31, 2016**
Exploration expense:		
Geological and geophysical costs	$ 5,729	$ 9,653
Other exploration expense	7,797	7,545
ARO settlements in excess of recorded liabilities	37	32
Total exploration expense	$ 13,563	$ 17,230

Exploration expense decreased primarily due to decreases in seismic expenses of $4.1 million, which are reflected in geological and geophysical costs.

Depreciation, depletion and amortization expense increased due to increased production.

?	Predecessor	
(in thousands)	**Year Ended December 31, 2017**	**Year Ended December 31, 2016**
Impairment of assets:		
Impairment of unproved properties	$ —	$ 16
Impairment of proved properties	1,188	366
Total impairment of assets	$ 1,188	$ 382

Impairment of assets increased due to the impairment of certain developed fields resulting from downward revisions in reserves on proved properties based on lower commodity prices, and performance or development drilling results that were below expectations.

?	Predecessor	
(in thousands)	**Year Ended December 31, 2017**	**Year Ended December 31, 2016**
General and administrative expense:		
Employee-related costs	$ 28,317	$ 26,226
Strategic costs - Business Combination Costs	8,118	—
Professional fees	10,567	10,577
Other	8,669	3,665
Total general and administrative expense	$ 55,671	$ 40,468

General and administrative expense increased primarily due to consulting and other fees directly attributable to the Business Combination plus a legal settlement of $4.7 million which is included in other G&A.

Below is a reconciliation of Upstream EBITDAX to operating income (loss):

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(in thousands)	Predecessor Year Ended December 31, 2017	Predecessor Year Ended December 31, 2016
Loss from continuing operations before income taxes	$ (12,840)	$ (134,279)
Interest expense	50,585	59,675
(Gain) loss on unrealized hedges	(4,170)	129,149
Exploration	13,563	17,230
Depreciation, depletion and amortization	89,115	53,755
Impairment of assets	1,188	382
Non-recurring Business Combination expense	8,118	—
Upstream Adjusted EBITDAX	$ 145,559	$ 125,912

Other Income (Expense)

?

(in thousands)	Predecessor Year Ended December 31, 2017	Predecessor Year Ended December 31, 2016
Alta Mesa Predecessor Credit Facility	$ 7,283	$ 8,826
Senior term loan facility	—	9,156
2024 Notes	39,375	37,272
Deferred financing cost amortization	2,732	3,905
Other	1,195	516
Total interest expense	50,585	59,675
Interest income and other	(1,075)	(884)
Loss on extinguishment of debt	—	18,151
Total other (income) expense	$ 49,510	$ 76,942

Interest expense decreased primarily due to the interest on our senior term loan facility that was repaid in full during the fourth quarter 2016.

Loss on extinguishment of debt resale from the 2016 repurchase of our $450 million outstanding 2018 Notes for which we recognized a loss of $13.5 million, which included unamortized discount and unamortized deferred financing costs write-offs.In addition, we repaid all amounts outstanding under the senior secured term loan facility of $127.7 million, which included accrued interest and a prepayment premium of $2.5 million. We recognized a loss related to the repayment of $4.7 million, which included write-offs of unamortized deferred financing costs totaling $2.0 million.

Loss on discontinued operations relates to the loss from the distribution of non-STACK oil and gas assets and related liabilities to the AM Contributor immediately prior to the Closing Date of the Business Combination.

Liquidity and Capital Resources

Our principal requirements for capital are to fund our day-to-day operations, development activities and to satisfy our contractual obligations related to servicing our debt and hedges. During 2018, our main sources of liquidity and capital resources came from the cash balance held following the Business Combination, cash flows generated from operations and borrowings under the Alta Mesa RBL and the KFM Credit Facility.

Our future drilling plans and capital budgets, as well as our midstream customers' plans, are subject to change based upon various factors, some of which are beyond our control, including drilling results, oil and gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, midstream availability, other working interest owner participation and regulatory matters. Any deferral of planned capital expenditures, particularly with respect to bringing new wells onto production, could reduce our anticipated production, revenue and cash flow, and may result in the

expiry of certain leases. However, because a large percentage of our acreage is held by production,we can alter our drilling program to minimize the risk of losing significant acreage.

Although we are currently capitally constrained, we strive to maintain financial flexibility and, if available on terms we find acceptable, we may utilize the capital markets to improve our capital structure or to facilitate our development program.If our operating cash flow is materially less than anticipated and other sources of capital are not available on acceptable terms, we may decide to curtail our capital spending.

During January 2019, we received an audit report from our external reserve engineers regarding their opinion of our 2018 ending proved reserves, which included multi-year development of our proved undeveloped reserves. During April 2019, in finalizing our financial reporting for 2018, we determined that we may fail to satisfy the leverage covenant under the Alta Mesa RBL during 2019.If we were to fail the leverage covenant, access to capital under the Alta Mesa RBL would likely be impaired, thus limiting our ability to satisfy the ability-to-drill threshold under the SEC's reserve recognition rule with respect to our future drilling locations. Thus, we did not recognize any proved undeveloped locations in the final December 31, 2018 reserve report. Should our ability to fund the required development costs improve in the future, we expect to re-recognize all or a portion of those reserves as proved.

Despite the absence of PUD locations in the 2018 reserve report, we operated 2 rigs during March through August of 2019 to develop our assets, particularly to focus on testing the spacing patterns we believe to be optimal, and to implement cost reduction strategies.Prior to the August 2019 redetermination of the Alta Mesa RBL, we anticipated drilling and bringing online approximately60 to 65 wells during 2019 while incurring approximately $140 million to $150 million of capital expenditures related to this development program. We also expected that an additional $20 million to $30 million could be incurred for other upstream non-operated projects, leasehold costs and capitalized workover activity. We will continue to evaluate the appropriate level of development, if any, going forward. We do not expect our operating cash flow to provide sufficient proceeds to meet our 2019 capital expenditure levels and we would be required to utilize cash on hand, including proceeds from borrowings under the Alta Mesa RBL, which we drew upon in April 2019 to substantially exhaust the remaining borrowing capacity.

During April 2019, our borrowing base was reduced from $400.0 million to $370.0 million as part of the semi-annual redetermination.In addition, we drew our remaining capacity to bring our outstanding borrowings to approximately $350 million and outstanding letters of credit of $20.0 million, with approximately $86.0 million of cash on hand after completing that borrowing.As of July 31, 2019, we held $87 million in cash. We did not obtain covenant relief as part of the redetermination, but that remains an important objective for us as we strive to continue to comply with all the terms of our debt. In August 2019, the lenders exercised their option to conduct an optional redetermination, pursuant to which they established a revised borrowing base of $200.0 million, which will require us to make monthly installments of $32.5 million for five months beginning in September 2019. As a consequence of reduced operating cash flow and a lowered borrowing base, we have limited ability to obtain the capital necessary to conduct our operations at desired levels. Additionally, if we are in default under the Alta Mesa RBL, the lenders could cease making amounts available, accelerate payment of amounts outstanding or seek other remedies any of which would further limit our access to the capital necessary to fund our capital expenditures. Following the August 2019 redetermination, we have decided to operate 1 rig starting in September. We will continue to evaluate how much, if any, development is appropriate going forward.

A detailed description of our debt including the significant terms and associated requirements is found in Item 8.

Alta Mesa RBL

In connection with the consummation of the Business Combination, all indebtedness at that time under the Alta Mesa senior secured revolving credit facility was repaid in full and we entered into the Alta Mesa RBL, which provided an aggregate maximum credit amount of$1.0 billion with an initial $350.0 million borrowing base, which will be redetermined semi-annually. The Alta Mesa RBL matures on February 9, 2023.In April 2018, the borrowing base was increased to $400.0 million, which was reaffirmed by the lenders during the fourth quarter of 2018.As of December 31, 2018, in addition to $161.0 million of borrowings outstanding, we also had $21.9 million of outstanding letters of credit, leaving a total borrowing capacity of $217.1 million remaining available for future use. On April 1, 2019, the borrowing base was reduced to $370.0 million upon completion of the regularly scheduled semi-annual redetermination. During April 2019, we drew $66.5 million to consume substantially all the remaining capacity under the Alta Mesa RBL. Pursuant to an optional redetermination in August 2019, the lenders established a revised borrowing base of $200.0 million.

The Alta Mesa RBL includes usual and customary covenants for facilities of its type and size. The covenants cover matters such as mandatory reserve reports, the responsible operation and maintenance of properties, certifications of compliance, required disclosures to the lenders, notices under other material instruments, and notices of sales of oil and gas properties. It also places limitations on the incurrence of additional indebtedness, restricted payments, distributions, investments outside of the ordinary course of business and the amount of hedges that we can put in place.We are not permitted to borrow funds if we are not in compliance with the covenants.

The Alta Mesa RBL bears interest at LIBOR plus an additional margin, based on the percentage of the borrowing base being utilized, ranging from 1.50% to 2.50%. There is also a commitment fee that ranges between 0.375% and 0.50% on the undrawn borrowing base amounts. The RBL may be prepaid without a premium. Interest on outstanding facility debt was LIBOR+2.00% at December 31, 2018.

The Alta Mesa RBL has two financial maintenance covenants (each as determined under the applicable definitions):

- A ratio of current assets to current liabilities of not less than 1.0; and
- A consolidated total leverage ratio of not more than 4.0.

During 2019, perhaps as early as the quarter ended September 30, 2019, we may be unable to satisfy the consolidated total leverage ratio and recognize the need to obtain covenant relief or to replace the Alta Mesa RBL with debt that would allow us to meet any attendant covenant requirements.

KFM Credit Facility

Effective May 30, 2018, KFM entered into a $300.0 million amended and restated senior secured revolving credit facility (the “KFM Credit Facility”) that replaced a prior credit facility. The KFM Credit Facility matures on May 30, 2023.

As of December 31, 2018, outstanding borrowings under the KFM Credit Facility totaled$174.0 million and there were no outstanding letters of credit, leaving a total borrowing capacity of $126.0 million remaining available for future use.

Availability under the KFM Credit Facility will be redetermined each fiscal quarter as the lesser of (1) the$300.0 million commitment under the KFM Credit Facility and (2) the maximum amount that, together with the aggregate amount of all then-outstanding consolidated funded indebtedness (other than indebtedness under the KFM Credit Facility) would result in KFM being in pro forma compliance with all applicable leverage ratios at such time.

As of July 31, we had $74 million of available borrowing capacity within our midstream credit silo, which we consider to be sufficient to carry out the contemplated capital program for 2019 and 2020. We expect to incur $40 to $50 million of capital costs during 2019 to improve our plant and to expand our gathering network.

Amendment and Waiver to the KFM Credit Facility

KFM failed to timely provide its lenders quarterly financial statements for the quarter ended December 31, 2018, and failed to provide the lenders notice in connection with its acquisition of the produced water assets from Alta Mesa, including the delivery of certain recorded instruments of transfer. In April 2019, KFM entered into an amendment and limited waiver (the “Amendment”) to the KFM Credit Facility to waive the defaults and events of default arising or resulting from those failures. The Amendment also extended the deadline for delivery of audited financial statements for 2018 and the deadline for the unaudited financial statements for the quarter ended March 31, 2019, which KFM subsequently met. Further, the Amendment adds provisions which limit the maximum amount of cash KFM can hold to $15.0 million. The Amendment also generally provides that any amendment to a material contract with an affiliate during a six-month period that causes a reduction to projected total revenue by more than 15% constitutes an event of default.

2024 Notes

Alta Mesa has $500.0 million in aggregate principal amount of 7.875% senior unsecured notes (the “2024 Notes”) that were issued at par by Alta Mesa and its wholly owned subsidiary Alta Mesa Finance Services Corp. during the fourth quarter of 2016. The 2024 Notes were issued in a private placement but were exchanged for substantially identical registered senior notes in November 2017.

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The 2024 Notes will mature in December 2024, and interest is payable semi-annually on June 15 and December 15 of each year. Alta Mesa may, from time to time, redeem certain amounts of the outstanding 2024 Notes at specified prices.

During the latter half of 2018 and into 2019, the 2024 Notes saw a substantial decrease in their trading prices.The ratings associated with the 2024 Notes also deteriorated, based on the rating agencies' belief that an exchange for less than par value had become more likely.In March 2019, we were notified that certain noteholders had formed a group, which purported to represent a majority of the face value of the 2024 Notes. We are in discussion with the group's financial and legal advisors and have provided them with requested information, but we cannot predict what will result from the discussions or whether they will yield a constructive deal.

The 2024 Notes include usual and customary covenants for debt of its type and size. The covenants cover matters such as the responsible operation and maintenance of properties, certificates of compliance, required disclosures to the lenders, notices under other material instruments, notices of sales of oil and gas properties and events of default. The covenants also limit our ability to incur secured debt, which may impact the quantum available to refinance our Alta Mesa RBL.

The 2024 Notes have no financial maintenance covenants.

We may from time to time seek to retire the 2024 Notes through cash purchases and/or exchanges for equity securities, in open market purchases, privately negotiated transactions or otherwise. Such repurchases or exchanges, if any, will depend on prevailing market conditions, our liquidity, contractual restrictions and other factors.

Related Party Receivables

On September 29, 2017, Alta Mesa entered into a $1.5 million promissory note receivable with its affiliate Northwest Gas Processing, LLC, which obligation was subsequently transferred to High Mesa Services, LLC ("HMS"), a subsidiary of HMI.The promissory note bears interest, which may be paid-in-kind and added to the principal amount, at a rate of 8% per annum and matured on February 28, 2019.At December 31, 2018 and 2017, amounts due under the promissory note totaled $1.7 million and $1.5 million, respectively. HMS defaulted under the terms of that promissory note when it was not paid when due on February 28, 2019, and HMS has failed to cure such default. Alta Mesa subsequently declared all amounts owing under the note immediately due and payable. Alta Mesa also has an $8.5 million promissory note receivable from HMS which matures on December 31, 2019, and bears interest at 8% per annum, which may be paid-in-kind and added to the principal amount.As of December 31, 2018, and 2017, the note receivable amounted to $11.7 million and $10.8 million, respectively. HMI disputes its obligations under the $1.5 million note and $8.5 million note referenced above as payable to Alta Mesa. We oppose HMI's claims and believe HMI's obligation under the notes to be valid assets of Alta Mesa and that the full amount is payable to Alta Mesa. We are pursuing remedies under both promissory notes and under applicable law in connection with repayment of the promissory note by HMS. As a result of the potential conflict of interest of certain of our directors who are also controlling holders and directors of HMI, our disinterested directors will address any potential conflicts of interest with respect to this matter. As of December 31, 2018, we established an allowance for doubtful accounts for the promissory notes totaling $13.4 million, the expense for which is included in general and administrative expense in 2018.

Interest income on the promissory notes amounted to approximately $0.9 million, $0.1 million, $0.9 million, and $0.8 million for the Successor Period, the 2018 Predecessor Period, and the years ended December 31, 2017 and 2016, respectively, all recorded as paid-in-kind and added to the balance due thereunder.

In connection with the Business Combination, we distributed our non-STACK oil and gas assets to a subsidiary of HMI, and certain subsidiaries of HMI agreed to indemnify and hold us harmless from any liabilities associated with those non-STACK oil and gas assets, regardless of when those liabilities arose. We also entered into a management services agreement (the "High Mesa Agreement") with HMI with respect to its non-STACK assets. Under the High Mesa Agreement, during the 180-day period following the Closing (the "Initial Term"), we agreed to provide certain administrative, management and operational services necessary to manage the business of HMI and its subsidiaries (the "Services"). Thereafter, the High Mesa Agreement automatically renewed for additional consecutive 180-day periods (each a "Renewal Term"), unless terminated by either party upon at least 90-days written notice to the other party prior to the end of the Initial Term or any Renewal Term.As compensation for the Services, HMI agreed to pay us each month (i) a management fee of $10,000, (ii) an amount equal to any and all costs and expenses incurred in connection with providing the Services.

Although the automatic renewal of this agreement occurred in the third quarter of 2018, the parties subsequently reached agreement to terminate the High Mesa Agreement effective January 31, 2019. Through April 1, 2019, we were obligated to take all actions that HMI reasonably requested to effect the transition of the Services from Alta Mesa to a successor service provider.

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During the transition period, HMI agreed to pay us (i) for all Services performed, (ii) an amount equal to our costs and expenses incurred in connection with providing the Services as provided for in the approved budget and (iii) an amount equal to our costs and expenses reimbursable pursuant to the High Mesa Agreement. Prior to 2018, we also incurred $0.8 million of costs for the direct benefit of HMI and the non-STACK assets, outside of the High Mesa Agreement, and pursuant to the High Mesa Agreement as "Receivables due from related party" in the balance sheets. As of December 31, 2018 (Successor) and December 31, 2017 (Predecessor), we had receivables of approximately $10.1 million and $0.8 million for costs and expenses incurred on HMI's behalf. Subsequent to year-end, we billed HMI $0.9 million for incremental MSA costs incurred and have received approximately $1.0 million in payments. HMI has disputed certain of these amounts billed by Alta Mesa. We are pursuing remedies under applicable law in connection with repayment of this receivable. There is no guarantee that HMI will pay the amounts it owes. In addition, our ability to collect these amounts or future amounts that may become due pursuant to indemnification obligations may be adversely impacted by liquidity and solvency issues at HMI. As a result, we have recognized an allowance for uncollectible accounts of $9.0 million to fully provide for the unremitted balance and may have future allowances for amounts incurred in 2019 prior to the termination of the MSA.We also may be subject to liabilities for the non-STACK oil and gas assets for which we should have been indemnified.We currently cannot estimate the extent of such liabilities.

Tax Receivable Agreement

We are party to a Tax Receivable Agreement ("TRA") with SRII Opco, the AM Contributor, and the Riverstone Contributor. This agreement generally provides for the payment by us of 85% of the amount of any realized net cash savings, in U.S. federal, state and local income tax in periods after the Business Combination as a result of (i) certain tax basis increases resulting from the exchange of SRII Opco Common Units for AMR Class A Common Stock (or, in certain circumstances, cash) pursuant to the redemption right or our right to effect a direct exchange of SRII Opco Common Units under the SRII Opco LPA, other than such tax basis increases allocable to assets held by KFM or otherwise used in KFM's midstream business, and (ii) interest paid or deemed to be paid by us as a result of, and additional tax basis arising from, any payments we make under the TRA. Also, under the TRA, we retain the benefit of the remaining 15% of these cash savings.

As of December 31, 2018, there had been one exchange of SRII Common Units which would trigger a payment under the TRA. This exchange occurred in November 2018 when 2,752,312 SRII Opco Common Units then held by the AM Contributor were converted into the same number of shares of AMR Class A Common Stock. We have calculated the tax basis increase resulting from this exchange, and the resulting potential future net cash savings in U.S. federal, state and local income tax, multiplied by 85% to arrive at a potential Tax Receivable Agreement liability.This amount would be due and payable by us if we actually realized these future cash tax savings. However, as of December 31, 2018, we have recorded a full valuation allowance on our other deferred tax assets determined in accordance with GAAP, and therefore we have not realized any savings and have not recorded a liability for such at this time. We are highly unlikely to recognize these attributes in 2019.

Cash Flows

	Successor	Predecessor		
(in thousands)	**February 9, 2018 Through December 31, 2018**	**January 1, 2018 Through February 8, 2018**	**Year Ended December 31, 2017**	**Year Ended December 31, 2016**
Cash from operating activities	$ 86,809	$ 26,336	$ 59,328	$ 131,704
Cash from investing activities	(560,547)	(37,913)	(345,876)	(224,298)
Cash from financing activities	501,205	16,932	283,920	91,238
Net increase (decrease) In cash, cash equivalents and restricted cash	$ 27,467	$ 5,355	$ (2,628)	$ (1,356)

Cash from operating activities

Cash provided by operating activities (including operating activities of discontinued operations) for the Successor Period and the 2018 Predecessor Period increased compared to the year ended December 31, 2017, primarily due to higher revenue inside of a relatively fixed cost structure. Changes in working capital and other assets and liabilities resulted in a decrease in cash of approximately$67.1 million and $35.9 million for the Successor Period and the year ended December 31, 2017, respectively. Changes in working capital and other assets and liabilities during the 2018 Predecessor Period resulted in an increase in cash of approximately $25.4 million.

Cash provided by operating activities (including operating activities of discontinued operations) for the year ended December 31, 2017 decreased compared the year ended December 31, 2016. The changes in our working capital accounts used $35.9 million of cash during 2017, as compared to having provided $28.1 million of additional cash in 2016.

Cash from investing activities

Cash used in investing activities (including investing activities of discontinued operations) for the Successor Period and the 2018 Predecessor Period increased compared to the year ended December 31, 2017, primarily due to net cash used for the Business Combination, increased Alta Mesa capital expenditures, and KFM capital expenditures made in the Successor Period. The cash used in investing activities was partially offset by proceeds withdrawn from the Trust Account in connection with the Business Combination.

Cash used in investing activities (including investing activities of discontinued operations) for the year ended December 31, 2017 increased compared the year ended December 31, 2016, primarily due to increased capital expenditures and acquisitions, partially offset by proceeds from the sale of the Weeks Island field and other assets.

Cash from financing activities

Cash provided by financing activities (including financing activities of discontinued operations) for the Successor Period and the 2018 Predecessor Period increased compared to the year ended December 31, 2017, primarily due to proceeds received in the Successor Period from the sale of our Class A Common Stock and warrants pursuant to a forward purchase agreement, partially offset by capital contributions in 2017 from the admission of Riverstone as a limited partner and from our former Class B limited partner, HMI.

Cash provided by financing activities (including financing activities of discontinued operations) for the year ended December 31, 2017 increased compared the year ended December 31, 2016. During 2017, we drew down $76.4 million, net of payments, under our Predecessor Credit Facility. During 2016, we used proceeds from the issuance of the 2024 Notes, capital contributions from our Class B limited partner and borrowings under our Alta Mesa Predecessor Credit Facility to repay Predecessor senior unsecured notes, the senior secured term loan facility and our senior secured revolving credit facility.

Risk Management Activities — Commodity Derivative Instruments

Oil and gas prices are inherently volatile and unpredictable. Accordingly, to achieve more predictable cash flow and reduce our exposure to adverse fluctuations in commodity prices, we have historically utilized commodity derivatives, such as swaps and

collars, to hedge price risk associated with our anticipated production and to underpin our development program. This helps reduce potential negative effects of reductions in gas prices but also reduces our ability to benefit from increases in gas prices. In certain circumstances, where we have unrealized gains in our derivative portfolio, we may choose to restructure existing derivative contracts or enter into new transactions to modify the terms of current contracts in order to realize the current value of our existing positions.

A swap has an established fixed price. When the settlement price is below the fixed price, the counterparty pays us an amount equal to the difference between the settlement price and the fixed price multiplied by the hedged contract volume. When the settlement price is above the fixed price, we pay our counterparty an amount equal to the difference between the settlement price and the fixed price multiplied by the hedged contract volume.

A put option has an established floor price. The buyer of that put option pays the seller a premium to enter into the put option. When the settlement price is below the floor price, the seller pays the buyer an amount equal to the difference between the settlement price and the strike price multiplied by the hedged contract volume. When the settlement price is above the floor price, the put option expires worthless.

A call option has an established ceiling price. The buyer of the call option pays the seller a premium to enter into the call option. When the settlement price is above the ceiling price, the seller pays the buyer an amount equal to the difference between the settlement price and the strike price multiplied by the hedged contract volume. When the settlement price is below the ceiling price, the call option expires worthless.

A put option and a call option may be combined to create a collar. A collar requires the seller to pay the buyer if the settlement price is above the ceiling price and requires the buyer to pay the seller if the settlement price is below the floor price.Our commodity derivatives allow us to mitigate the potential effects of the variability in operating cash flow thereby providing increased certainty of cash flows to support our capital program and to service our debt. Our derivatives provide only partial price protection against declines in natural gas prices and partially limit our potential gains from future increases in prices. The following table summarizes our remaining derivatives.

We had the following call and put derivatives at December 31, 2018:

OIL

Settlement Period and Type of Contract	Volume in bbls	Weighted Average	Range High	Range Low
2019				
Price Swap Contracts	182,500	$ 63.03	$ 63.03	$ 63.03
Collar Contracts				
Short Call Options	2,701,000	66.31	75.20	56.50
Long Put Options	2,883,500	53.80	62.00	50.00
Short Put Options	2,883,500	42.72	52.00	37.50
2020				
Collar Contracts				
Short Call Options	585,600	64.32	73.80	59.55
Long Put Options	1,537,200	55.54	62.50	50.00
Short Put Options	1,537,200	44.64	50.00	37.50

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NATURAL GAS

Settlement Period and Type of Contract	Volume MMBtu	Weighted Average	Range High	Range Low
2019				
Price Swap Contracts	10,905,000	$ 2.69	$ 3.09	$ 2.64
Collar Contracts				
Short Call Options	4,000,000	3.31	3.75	3.17
Long Put Options	3,550,000	2.81	2.90	2.70
Short Put Options	2,425,000	2.27	2.40	2.20
2020				
Collar Contracts				
Short Call Options	2,275,000	3.19	3.20	3.17
Long Put Options	9,150,000	2.57	2.70	2.50
Short Put Options	9,150,000	2.07	2.20	2.00
2021				
Collar Contracts				
Long Put Options	2,250,000	2.65	2.65	2.65
Short Put Options	2,250,000	2.15	2.15	2.15

In those instances where contracts are identical as to time period, volume and strike price, and counterparty, but opposite as to direction (long and short), the volumes and average prices have been netted in the two tables above. Prices stated in the table above for oil may settle against either the NYMEX index or may reflect a mix of positions settling on various combinations ofbenchmarks.

We had the following basis swaps at December 31, 2018:

Total Gas Volumes in MMBtu over Remaining Term[(1)]	Reference Price 1 [(1)]	Reference Price 2 [(1)]	Period	Weighted Average Spread ($ per MMBtu)
460,000	OneOK	NYMEX Henry Hub	Jul '19 — Dec '19	$ (0.93)
17,950,000	Tex/OKL Panhandle Eastern Pipeline	NYMEX Henry Hub	Jan '19 — Dec '19	(0.68)
910,000	Tex/OKL Panhandle Eastern Pipeline	NYMEX Henry Hub	Jan '20 — Mar '20	(0.49)
2,365,000	San Juan	NYMEX Henry Hub	Jan '19 — Oct '19	(0.78)

(1) Represents short swaps that fix the basis differentials between OneOK, Tex/OKL Panhandle Eastern Pipeline ("PEPL"), San Juan and NYMEX Henry Hub.

Contractual Obligations

The following table summarizes our contractual obligations as of December 31, 2018 (in thousands):

?	Year Ended December 31,				
?	Total	2019	2020-2021	2022-2023	Thereafter
Long-term debt	$ 835,000	$ —	$ —	$ 335,000	$ 500,000
Interest on long-term debt [(1)]	322,077	59,663	119,326	103,713	39,375
Operating leases	26,945	2,819	5,762	6,145	12,219
Firm transportation contracts	186,752	19,014	36,704	36,007	95,027
Drilling rigs [(2)]	6,068	6,068	—	—	—
Abandonment liabilities [(3)]	11,552	2,079	1,755	281	7,437
Total	$ 1,388,394	$ 89,643	$ 163,547	$ 481,146	$ 654,058

(1) Interest on the outstanding balance under the Alta Mesa RBL and the KFM Credit Facility is payable quarterly; and for the 2024 Notes is payable semiannually. The weighted average rates on our outstanding borrowings as of December 31, 2018 of 6.75% and 5.41% were utilized to calculate the projected interest for our Alta Mesa RBL and KFM Credit Facility, respectively. Projected obligation amounts are based on the payment schedules for interest, and are not presented on an accrual basis.
(2) Obligations for the cost of drilling rigs are included at the gross contractual value. Due to our various working interests where the drilling rig contracts will be utilized, it is not feasible to estimate a net contractual obligation. Net payments under these contracts are accounted for as capital additions to our oil and gas properties and could be less than the gross obligation disclosed.
(3) Represents estimated discounted costs to retire and remove long-lived assets at the end of their operations.

Our contracted commitments to secure capacity on third party pipelines for transportation of our natural gas are as follows

	Upstream	Midstream(1)	Total
2019 (MMBtu)	54,750,000	49,865,000	104,615,000
2020 (MMBtu)	54,900,000	45,750,000	100,650,000
2021 (MMBtu)	54,750,000	45,625,000	100,375,000
2022 (MMBtu)	54,750,000	40,275,000	95,025,000
2023 (MMBtu)	—	36,500,000	36,500,000
Thereafter	—	450,450,000	450,450,000

(1) Total cash payment requirements for the committed capacity are $6,778,000 in 2019, $6,116,000 each in 2020 and 2021, $5,859,000 in 2022, $5,676,000 in 2023 and $70,004,000 thereafter.

We have entered into certain firm commitments intended to secure capacity on third party pipelines for transportation of our natural gas.We currently do not utilize the full amount of our contracted capacity. However, we strive to release capacity to third parties for a fee.

Off-Balance Sheet Arrangements

As of December 31, 2018, other than as described below, we had no guarantees of third-party obligations, and our off-balance sheet obligations include our obligations under operating leases. Alta Mesa is also contingently liable for bonds posted in the aggregate amount of $1.3 million, primarily to cover future abandonment costs, and $21.9 million in letters of credit provided under the Alta Mesa RBL. We typically enter into short-term drilling contracts which are customary in the oil and gas industry. We have no other off-balance sheet arrangements that are reasonably likely to materially affect our liquidity and capital resources.

Alta Mesa and HMI are both parties to a payment and indemnity agreement with our current surety provider in connection with regulatory bonds executed on behalf of both companies covering STACK and non-STACK assets. The surety bonds in place and covered by the joint indemnity agreement for HMI non-STACK properties total approximately $15 million. The surety has requested posting of collateral. If HMI cannot post collateral or satisfy its indemnity obligations, Alta Mesa may be required post collateral or otherwise satisfy HMI's obligations associated with HMI surety bonds covering non-STACK assets.

Critical Accounting Policies and Estimates

Our financial statements are prepared in accordance with GAAP. In connection with preparing our financial statements, we are required to make assumptions and estimates about future events and apply judgments that affect the reported amounts of assets, liabilities, revenue, expense and the related disclosures. We base our assumptions, estimates and judgments on historical experience, current trends and other factors that management believes to be relevant at the time we prepare our consolidated financial statements. On a regular basis, we review the accounting policies, assumptions, estimates and judgments to ensure that our financial statements are presented fairly and in accordance with GAAP. However, because future events and their effects cannot be determined with certainty, actual results could differ materially from our assumptions and estimates.

Our significant accounting policies are discussed in our audited financial statements included elsewhere in this Annual Report. We believe that the following accounting estimates are those most critical to fully understanding and evaluating our reported

financial results, and they require our most difficult, subjective or complex judgments, resulting from the need to make estimates about the effect of matters that are inherently uncertain.

Oil and Gas Reserves

Policy Description

Proved oil and gas reserves are the estimated quantities of oil and gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. In calculating cash inflows for reserves, we use an unweighted average of the preceding 12-month first-day-of-the-month prices for determination of proved reserve values and for annual proved reserve disclosures. We assume continued use of technologies with demonstrated success of yielding expected results, including the use of drilling results, well performance, well logs, seismic data, geological maps, well stimulation techniques, well test data and reservoir simulation modeling.

In calculating cash outflows for reserves, we use well costs and operating costs prevailing during the preceding year, but more heavily weighted toward recent demonstration levels, which are then held constant into future periods. Our estimates of proved reserves are determined and reassessed at least annually using available geological and reservoir data as well as production performance data. Revisions may result from changes in, among other things, reservoir performance, prices, economic conditions and governmental policies.

We limit our future development program to only those wells that we expect to be developed within five years of their initial recognition.

Judgments and Assumptions

All of our reserve information is based on estimates. Estimates of gas reserves are prepared in accordance with guidelines established by the SEC. Reservoir engineering is a subjective process of estimating recoverable underground accumulations of oil and gas. There are numerous uncertainties inherent in estimating recoverable quantities of proved oil and gas reserves. Uncertainties include the projection of future production rates and the expected timing of development expenditures. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. As a result, proved reserve estimates may be different from the quantities of oil and gas that are ultimately recovered.

The passage of time provides more qualitative information regarding estimates of reserves, and revisions are made to prior estimates to reflect updated information. If future significant revisions are necessary that reduce previously estimated reserve quantities, it could result in recognition of impairments, such as those seen in 2018 where our year-end reserves reduced substantially compared to reserves at the time of the Business Combination. In addition to using estimates of proved reserves to assess for impairment, we also rely heavily on them in the calculation of depletion expense. For example, if estimates of proved reserves decline, the depletion rate and resulting expense will increase, resulting in a decrease in net income. A decline in estimates of proved reserves could also cause us to perform an impairment analysis to determine whether the carrying amount of oil and gas properties exceeds fair value, which would result in an impairment charge, reducing net income.

Successful Efforts Method of Accounting for Oil and Gas Properties

Policy Description

Oil and gas producing activities are accounted for using the successful efforts method under which lease acquisition costs and all development costs, including unsuccessful development wells, are capitalized.

Accounting policies include:

Unproved Properties — Costs associated with the acquisition of leases are capitalized as incurred. These costs consist of amounts incurred to obtain a mineral interest or right in a property, such as a lease, options to lease, and related broker and other fees.Properties are classified as unproved until proved reserves are recognized, at which time the related costs are transferred to proved oil and gas properties, or when leases expire or are sold.

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Proved Oil and Gas Properties — Costs incurred to lease, drill, complete and equip proved reserves are capitalized. All costs incurred to drill and equip successful exploratory wells, development wells, development-type stratigraphic test wells, and service wells, including unsuccessful development wells, are capitalized.

Impairment — Our unproved properties consist of leasehold and other capital costs incurred for properties for which no proved reserves have been identified. In determining whether unproved property is impaired, we consider numerous factors including recent leasing activity, current development plans, expected resource recovery, recent drilling results in the area, our geologists' evaluation of the property and the remaining lease term for the property. If a potential impairment exists, we develop a cash flow model based on estimated resource potential and, combined with a market approach, estimate fair value of our properties. Our cash flow estimates for probable and possible resource potential is reduced by additional risk-weighting factors. We then reduce the carrying amount of unproved properties, if higher, to estimated fair value.

The capitalized costs of proved oil and gas properties are reviewed at least annually, or whenever events or changes in circumstances indicate that a potential impairment may have occurred. The determination of recoverability is based on comparing the estimated undiscounted future net cash flows at a producing field level to the carrying value of the assets. If the carrying amount exceeds the estimated undiscounted future net cash flows, we adjust the carrying amount of the properties to fair value. For our proved oil and gas properties, we estimate fair value by discounting the projected future cash flows at an appropriate risk-adjusted discount rate.

Judgments and Assumptions

Our impairment analysis requires us to apply judgment in identifying impairment indicators and estimating future cash flows of our oil and gas properties. If actual results are not consistent with our assumptions and estimates or our assumptions and estimates change due to new information, we may be exposed to an impairment charge.

Key assumptions used to determine the undiscounted future cash flows include estimates of future production, timing of new wells coming on line, differentials, net estimated operating costs, anticipated capital expenditures and future commodity prices. Our discussion of the judgments inherent in reserve estimation above has information with direct bearing on the judgments surrounding our depletion calculation and impairment analysis. However, in conducting our impairment analysis, we also replace pricing assumptions with future price estimates and we include values for our probable and possible resource potential in determining fair value.

Lower net undiscounted cash flows can result in the carrying amount of our oil and gas properties exceeding the net undiscounted cash flows, which results in an impairment expense. Changes in forward commodity prices and differentials, changes in levels and timing of capital and operating expenses, and changes in production among other items can result in lower net undiscounted cash flows. Forward commodity prices can change quickly and unexpectedly which can negatively impact forward commodity prices, causing lower undiscounted net cash flows.As an example, we utilized forward commodity price estimates as of December 31, 2018, in our future net cash flow estimates. These price estimates contributed to an impairment charge of $1.3 billion being recorded during the Successor Period with respect to our proved oil and gas properties.Forward commodity price estimates increased shortly after the end of 2018. Had we been able to use mid-January 2019 forward commodity price estimates instead, our impairment charge would have decreased by approximately $100 million. Similarly, future capital and lease operating costs are uncertain and can change quickly based on regional oil and gas drilling activity, steel and other raw material prices, transportation costs and regulatory requirements, among other factors. Increased capital and lease operating costs would result in lower net undiscounted cash flows. Production estimates are determined based on field activities and future drilling plans.

Drilling and field activities require significant judgments in the evaluation of all available geological, geophysical, engineering and economic data. As such, actual results may materially differ from predicted results, which could lower production and net undiscounted cash flows.

Intangible Assets

Policy Description

In connection with the acquisition of KFM, we recorded the estimated fair value of acquired customer contracts and related customer relationships as intangible assets, which were valued using the income approach, and presented as Intangible Assets.

These intangible assets, all of which relate to the Midstream segment, have definite lives and are subject to amortization utilizing an accelerated attrition method over their economic lives.

We assess intangible assets for impairment, together with related underlying long-lived assets, whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. If required, we would recognize an impairment to reduce the carrying amount of an intangible asset to its fair value.

Judgments and Assumptions

Recoverability of the carrying amount of our intangible assets is first determined by whether cash flows at the lowest level associated with the asset or a related asset group exceeds the carrying amount of the asset or asset group. Cash flows on our contracts are generally not separable from cash flows associated with our other midstream assets, which in total comprise the related asset group. If the undiscounted cash flows of the asset group are less than carrying value of the asset group, an impairment may exist and is required to be measured by the amount that the carrying value of the intangible assets exceed the fair value of those assets.

The determination of the estimated fair value of acquired customer contracts and related customer relationships requires significant judgment in determining discounted cash flows associated with those contracts and relationships. Key assumptions include estimates of revenue associated with those contracts, the probability of renewals at the end of contractual terms, operating expenses associated with the contracts, allocated costs associated with contributory assets such as working capital, fixed assets and a trained and assembled workforce and a market participant discount rate.

Events that may indicate an impairment of intangible assets include changes in market conditions, changes in the utilization of other related assets, changes in the regulatory environment and the loss of one or more significant customers. As an example, our stock price declined significantly during the Successor Period and commodity prices dropped sharply during the fourth quarter of 2018. These factors, along with results from our 2018 drilling program, led to significant changes in our future upstream operating plans and negatively impacted future expected cash flows of KFM, which caused us to conclude that our intangible assets were fully impaired at December 31, 2018. Had our drilling results been more in line with expectations or had third parties brought more volumes on-line on our system, our impairment could have been reduced or avoided altogether.

Goodwill

Policy Description

Goodwill represents the excess of the purchase price over the estimated fair value of the identified assets and liabilities acquired. Goodwill is not amortized but is subject to periodic impairment testing at least annually, or whenever events and circumstances indicate an impairment may exist. Any identified impairment of goodwill will be recognized as the amount by which a reporting unit's carrying value exceeds its fair value, not to exceed the carrying amount of goodwill.

Judgments and Assumptions

The allocation of the cost of each acquisition to the tangible and intangible assets acquired and liabilities assumed requires significant judgment in determining the fair value of those assets and liabilities at the time of the acquisition. Such a determination is often based on an estimate of future discounted cash flows of the business acquired or the use of other valuation techniques specific to individual groups of assets or liabilities.

Key assumptions used in estimating future discounted cash flows includes future revenue, future costs of operations, future capital spending, long-term revenue and earnings growth assumptions, highest and best use of assets acquired and a market participant discount rate. In the case of our acquisition of KFM, estimated production from our upstream oil and gas properties that dedicated their production to KFM was also key to determining the amount of estimated revenue of the business acquired.

Once the fair value of the assets acquired and liabilities assumed have been determined, any residual difference is allocated to goodwill to arrive at the total purchase consideration. Goodwill is then assigned to a reporting unit for purposes of evaluating future impairment.

In periods subsequent to the acquisition, we are required to at least annually determine if the fair value of the business acquired is in excess of its current carrying value. If not, goodwill would be impaired for the difference between carrying value and fair value, to the extent of the amount of recorded goodwill. In assessing whether impairment indicators exist, we evaluate changes

in market conditions, changes in the expected utilization of the assets acquired, changes in the regulatory environment or the loss of significant customers, among other considerations. Determination of the fair value of the business is generally based on an estimate of future discounted cash flows involving key assumptions as described above.

As noted above under "Intangible Assets", a number of factors occurred during the Successor Period and in the fourth quarter of 2018 that led to significant changes in our future upstream operating plans and negatively impacted future expected cash flows of KFM, which caused us to conclude that the goodwill associated with our acquisition of KFM was fully impaired atDecember 31, 2018.

Derivatives

Policy Description

We measure our derivatives at estimated fair value and record them as assets or liabilities in the balance sheet. Changes in fair value of our derivatives are recognized as "Gain (loss) on derivatives" in the statement of operations, along with realized gains or losses from the settlement of matured derivatives.

We net the value of our derivative assets and liabilities with the same counterparty for purposes of presentation in our consolidated balance sheets where master netting agreements are in place.

Judgments and Assumptions

We have chosen not to elect hedge accounting treatment for our derivatives, which results in all changes in fair value of our derivatives being recognized each period in our statement of operations. Had we elected to treat some or all of our derivatives as cash flow hedges, any change in fair value of the derivative that effectively offsets the change in fair value of the underlying transaction, would have been deferred in other comprehensive income until the underlying transaction affected earnings at which time the offsetting impact of the hedge would have been reclassified from other comprehensive income to earnings. Hedge ineffectiveness would have been recognized in earnings each period under this election.

The estimates of the fair values of our commodity derivatives require substantial judgment. Valuations are based upon multiple factors such as futures prices, volatility data, length of time to maturity, credit risks and interest rates. We compare our estimates of fair value for these instruments with valuations obtained from independent third parties and counterparty valuation confirmations. We also make evaluations around the creditworthiness of counterparties where our derivatives are in the money. The values we report in our financial statements change as these estimates are revised to reflect actual results. Future changes to forecasted or realized commodity prices could result in significantly different values and realized cash flows for such instruments.

Recent Accounting Pronouncements

Our audited financial statements in Item 8 contain a description of recent accounting pronouncements.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

We are exposed to certain market risks that are inherent in our financial statements that arise in the normal course of business. We may enter into derivatives to manage or reduce market risk, but we do not enter into derivatives for speculative purposes.The Alta Mesa RBL also has mandatory minimum hedging requirements. We do not designate these derivatives as hedges for accounting purposes.

Commodity Price Risk and Hedges

Our major market risk exposure is to prices for oil, gas and NGLs, which have historically been volatile. As such, future results are subject to change due to changes in these prices. Realized prices are primarily driven by the prevailing worldwide price for oil and regional prices for gas. We have used, and expect to continue to use, derivatives to reduce our exposure to the risks of price changes. Pursuant to our risk management policy, we engage in these activities as a hedging mechanism against low prices and price volatility associated with developed and undeveloped reserves.

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Forecasted production from proved reserves is estimated in our December 2018 reserve report using prices, costs and other assumptions required by SEC rules. Our actual production will vary from the amounts estimated in the report, perhaps materially. Our risk factors in Item 1A contain discussions of significant matters related to future production.

The fair value of our oil and gas derivatives and basis swaps at December 31, 2018 was a net asset of $17.5 million. A 10% increase or decrease in oil and gas prices with all other factors held constant would result in an unrealized loss or gain, respectively, in the fair value (generally correlated to our estimated future net cash flows from such instruments) of our oil and gas commodity contracts of approximately $14.9 million (decrease in value) or $14.2 million (increase in value), respectively, as of December 31, 2018.

Counterparty and Customer Credit Risk

Our derivatives expose us to credit risk in the event of nonperformance by counterparties. While we do not require them to post collateral, we do monitor the credit standing of such counterparties, all of which have investment grade ratings.

Our principal ongoing exposures to credit risk are through receivables resulting from joint interest receivables and receivables from the sale of our oil and gas production. The inability or failure of our customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results. However, we believe the credit quality of our purchasers of production and other working interest owners is high.

Much of our oil and gas production in 2018, including certain processed gas and NGLs, was sold through a marketing agreement with ARM Energy Management, LLC (“ARM”), who marketed and sold our oil and gas production and processed products under short-term contracts, generally with month-to-month pricing based on published indices, adjusted for transportation, location and quality. ARM generally remitted monthly collections of these sales to us, net of its fee. For the Successor Period, ARM marketed $336.2 million, or 71% of our total operating revenue for the period. We are significantly exposed to ARM’s credit quality but have experienced no losses to date.

Effective as of June 1, 2019, we have terminated our oil and NGL marketing agreement with ARM and will market such products internally. We have extended the term of our gas marketing agreement with ARM through November 30, 2019. With respect to gas sales, ARM continues to collect payments from purchasers, deducts their marketing fee and remits the balance to us.

Joint operations receivables arise from billings to entities that own interests in the wells we operate. These entities participate in our wells primarily based on their ownership in leases on which we intend to drill. We have little ability to control whether these entities will participate in our wells.

Interest Rates

We are subject to interest rate risk on our long-term fixed interest rate debt and variable interest rate borrowings. Although in the past we have used interest rate swaps to mitigate the effect of fluctuating interest rates on interest expense, we currently have no open interest rate derivatives. A 1% increase in interest rates would increase interest expense on the KFM Credit Facility by approximately $1.7 million and would increase interest expense on the Alta Mesa RBL by approximately $1.6 million, based on the balances outstanding at December 31, 2018.

Inflation

Inflation in the United States has been relatively low in recent years and did not have a material impact on our results of operations for the Successor Period, the 2018 Predecessor Period or the year ended December 31, 2017. Although the impact of inflation has been insignificant in recent years, it could cause upward pressure on the cost of oilfield services, equipment and general and administrative expenses.

Item 8. Financial Statements and Supplementary Data

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Stockholders and Board of Directors
Alta Mesa Resources, Inc.:

Opinion on Internal Control Over Financial Reporting

We have audited Alta Mesa Resources, Inc. and subsidiaries' (the Company) internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. In our opinion, because of the effect of the material weaknesses, described below, on the achievement of the objectives of the control criteria, the Company has not maintained effective internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of the Company as of December 31, 2018 the related consolidated statements of operations, changes in stockholders' equity (Successor), changes in partners' capital (Predecessor), and cash flows for the period from January 1, 2018 to February 8, 2018 (Predecessor) and for the period from February 9, 2018 to December 31, 2018 (Successor), and the related notes (collectively, the consolidated financial statements), and our report dated August 26, 2019 expressed an unqualified opinion on those consolidated financial statements.

A material weakness is a deficiency, or a combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of the company's annual or interim financial statements will not be prevented or detected on a timely basis. The following material weaknesses have been identified and included in management's assessment:

Control Environment
- Insufficient internal resources with appropriate knowledge and expertise to design and implement, document and operate effective financial reporting processes and internal controls
- Insufficient training of personnel on the COSO 2013 Framework and its implications on financial reporting and their related internal control roles and responsibilities
- Ineffective assignment of personnel with sufficient experience to review information provided to third-party business valuation and technical accounting specialists and monitor the activities performed by them
- Ineffective policies and procedures that held personnel accountable for defined internal control responsibilities through performance measurement plans and goals

Risk Assessment
- Ineffective continuous risk assessment process to identify and evaluate the risk of misstatement due to error in recurring and nonrecurring financial reporting processes and to establish controls to mitigate those risks
- Ineffective identification and assessment of risk of misstatement due to error resulting from changes in operations affecting financial reporting and internal control over both recurring and nonrecurring transactions

Information and Communication
- Ineffective controls over the identification and processing of relevant and reliable information
- Ineffective internal communication of such information on a timely basis to personnel responsible for financial reporting, and to those charged with governance

Monitoring Activities
- Ineffective monitoring activities across the Company to ensure that the processes and internal controls related to the five COSO 2013 Framework components and underlying principles were present and functioning
- Ineffective identification and timely remediation of control deficiencies

Control Activities
- Ineffective control activities over both recurring and nonrecurring transactions including the Business Combination
- Ineffective written policies and procedures at a sufficient level of detail to affect the design and evidence the consistent and timely operation of the controls

- Ineffective controls over the financial statement close and disclosure process, including the completeness, existence and accuracy of the financial information
- Ineffective user access information technology (IT) controls to production volumes application and data base and payroll application and ineffective automated controls and manual controls that are dependent upon the completeness and accuracy of information derived from these IT applications
- Ineffective controls over the use of certain spreadsheets
- Ineffective management review controls over various complex accounting estimates

The material weaknesses were considered in determining the nature, timing, and extent of audit tests applied in our audit of the 2018 consolidated financial statements, and this report does not affect our report on those consolidated financial statements.The Company acquired Kingfisher Midstream, LLC during 2018, and management excluded from its assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2018, Kingfisher Midstream LLC's internal control over financial reporting associated with total assets of32% and operating revenue of 12% of the successor period. Our audit of internal control over financial reporting of the Company also excluded an evaluation of the internal control over financial reporting of Kingfisher Midstream, LLC.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Report on ICFR. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control Over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ KPMG LLP

Houston, Texas
August 26, 2019

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Stockholders and Board of Directors
Alta Mesa Resources, Inc.:

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of Alta Mesa Resources, Inc. and subsidiaries (the Company) as of December 31, 2018, the related consolidated statements of operations, changes in stockholders' equity (Successor), changes in partners' capital (Predecessor) and cash flows for the period from January 1, 2018 to February 8, 2018 (Predecessor) and from February 9, 2018 to December 31, 2018 (Successor), and the related notes (collectively, the consolidated financial statements). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and the results of its operations and its cash flows for the period from January 1, 2018 to February 8, 2018 (Predecessor) and for the period from February 9, 2018 to December 31, 2018 (Successor), in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission", and our report datedAugust 26, 2019 expressed an adverse opinion on the effectiveness of the Company's internal control over financial reporting.

Going Concern

The accompanying consolidated financial statements have been prepared assuming that the Company will continue as a going concern. As discussed in Note 2 to the consolidated financial statements, the Company has suffered recurring losses from operations, and is facing risks and uncertainties surrounding its credit facility covenant compliance that raise substantial doubt about its ability to continue as a going concern. Management's plans in regard to these matters are also described in Note 2. The consolidated financial statements do not include any adjustments that might result from the outcome of this uncertainty.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ KPMG LLP

We have served as the Company's auditor since 2018.

Houston, Texas
August 26, 2019

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Stockholders and Board of Directors
Alta Mesa Resources, Inc.
Houston, Texas

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheet of Alta Mesa Holdings, LP, the predecessor to Alta Mesa Resources, Inc., (the "Company") as of December 31, 2017, the related consolidated statements of operations, changes in partners' capital, and cash flows for each of the two years in the period ended December 31, 2017, and the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2017, and the results of its operations and its cash flows for each of the two years in the period ended December 31, 2017, in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. The Company was not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ BDO USA, LLP

We served as the Company's auditor from 2014 to 2018.

Houston, Texas
March 29, 2018, except for Note 10, as to which the date is May 17, 2019

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ALTA MESA RESOURCES, INC.
CONSOLIDATED STATEMENTS OF OPERATIONS
(in thousands, except per share data)

?	Successor	Predecessor		
	February 9, 2018 Through December 31, 2018	January 1, 2018 Through February 8, 2018	Year Ended December 31, 2017	Year Ended December 31, 2016
Revenue				
Oil	$ 323,299	$ 30,972	$ 194,423	$ 105,811
Natural gas	43,407	4,276	37,794	20,021
Natural gas liquids	43,039	4,000	31,445	14,174
Sales of gathered production	31,506	—	—	—
Midstream revenue	27,460	—	—	—
Other	4,762	888	5,724	2,350
Operating revenue	473,473	40,136	269,386	142,356
Gain on sale of assets	4,751	840	28	3
Gain on acquisitions of oil and gas properties	—	—	1,668	—
Gain (loss) on derivatives	(10,247)	6,663	8,287	(40,460)
Total revenue	467,977	47,639	279,369	101,899
Operating expenses				
Lease operating	56,827	4,408	43,953	29,567
Transportation, processing and marketing	19,293	3,725	29,460	11,628
Midstream operating	15,221	—	—	—
Cost of sales for purchased gathered production	31,247	—	—	—
Production taxes	16,865	953	5,494	2,765
Workovers	5,563	423	4,255	3,441
Exploration	34,085	7,003	13,563	17,230
Depreciation, depletion and amortization	160,942	11,670	89,115	53,755
Impairment of assets	3,205,051	—	1,188	382
General and administrative	131,052	21,234	55,671	40,468
Total operating expenses	3,676,146	49,416	242,699	159,236
Operating income	(3,208,169)	(1,777)	36,670	(57,337)
Other income (expense)				
Interest expense	(43,296)	(5,511)	(50,585)	(59,675)
Interest income and other	2,049	172	1,075	884
Loss on debt extinguishment	—	—	—	(18,151)
Total other income (expense), net	(41,247)	(5,339)	(49,510)	(76,942)
Loss from continuing operations before income taxes	(3,249,416)	(7,116)	(12,840)	(134,279)
Income tax provision (benefit)	(69)	—	6	—
Loss from continuing operations	(3,249,347)	(7,116)	(12,846)	(134,279)
Loss from discontinued operations, net of tax	—	(7,746)	(64,815)	(33,642)
Net loss	(3,249,347)	$ (14,862)	$ (77,661)	$ (167,921)
Net loss attributable to non-controlling interest	(1,724,648)			
Net Loss Attributable to Alta Mesa Resources, Inc. Stockholders	$ (1,524,699)			

?

Net Loss Per Common Share Attributable To Alta Mesa Resources, Inc. Stockholders:	
Basic and diluted	$ (8.71)

The accompanying notes are an integral part of these financial statements.

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ALTA MESA RESOURCES, INC.
CONSOLIDATED BALANCE SHEETS
(in thousands, except shares and per share data)

?	Successor	Predecessor
?	December 31, 2018	December 31, 2017
ASSETS		
Current assets		
Cash and cash equivalents	$ 26,854	$ 3,660
Restricted cash	1,001	1,269
Accounts receivable, net	87,842	76,161
Other receivables	6,331	1,388
Related party receivables	3,341	790
Prepaid expenses and other	1,125	2,932
Derivatives	16,423	216
Current assets — discontinued operations	—	5,195
Total current assets	142,917	91,611
Property, plant and equipment		
Oil and gas properties, successful efforts method, net	763,337	894,630
Other property, plant and equipment	444,269	32,140
Total property, plant and equipment, net	1,207,606	926,770
Other assets		
Equity method investment	1,100	—
Deferred financing costs	3,195	1,787
Notes receivable from related party	—	12,369
Intangible assets, net	—	—
Goodwill	—	—
Deposits and other long-term assets	65	9,067
Derivatives	2,947	8
Noncurrent assets — discontinued operations	—	43,785
Total other assets	7,307	67,016
Total assets	$ 1,357,830	$ 1,085,397

The accompanying notes are an integral part of these financial statements.

	Successor	Predecessor
	December 31, 2018	December 31, 2017
LIABILITIES, PARTNERS' CAPITAL AND STOCKHOLDERS' EQUITY		
Current liabilities		
Current portion of debt	$ 690,123	$ —
Accounts payable and accrued liabilities	247,439	170,489
Accounts payable to affiliate	—	5,476
Advances from non-operators	5,193	5,502
Advances from related party	9,839	23,390
Asset retirement obligations, current potion	2,079	69
Derivatives	1,710	19,303
Current liabilities — discontinued operations	—	15,419
Total current liabilities	956,383	239,648
Long-term liabilities		
Asset retirement obligations, net of current portion	9,473	10,400
Long-term debt	174,000	607,440
Derivatives	180	1,114
Other long-term liabilities	1,667	5,488
Noncurrent liabilities — discontinued operations	—	66,862
Total long-term liabilities	185,320	691,304
Total liabilities	1,141,703	930,952
Commitments and contingencies (Note 18)		
Preferred stock, $0.0001 par value		
Class A: 1,000,000 shares authorized; 3 shares issued; 2 outstanding	—	—
Class B: 1,000,000 shares authorized; 1 share issued and outstanding	—	—
Partners' capital	—	154,445
Stockholders' equity		
Common stock, $0.0001 par value		
Class A: 1,200,000,000 shares authorized; 180,072,227 shares issued and outstanding	18	—
Class C: 280,000,000 shares authorized; 202,169,576 shares issued and outstanding	20	—
Additional paid in capital	1,503,382	—
Accumulated deficit	(1,532,813)	—
Total stockholders' equity/partners' capital	(29,393)	154,445
Noncontrolling interest	245,520	—
Total equity	216,127	154,445
Total liabilities, partners' capital and stockholders' equity	$ 1,357,830	$ 1,085,397

The accompanying notes are an integral part of these financial statements.

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ALTA MESA RESOURCES, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

?	Successor	Predecessor		
	February 9, 2018 Through December 31, 2018	**January 1, 2018 Through February 8, 2018**	**Year Ended December 31, 2017**	**Year Ended December 31, 2016**
Cash flows from operating activities:				
Net loss	$ (3,249,347)	$ (14,862)	$ (77,661)	$ (167,921)
Adjustments to reconcile net loss to cash from operating activities:				
Depreciation, depletion and amortization	160,942	12,554	113,634	95,075
Provision for uncollectible related party receivables	22,438	—	—	—
Impairments	3,205,051	5,560	30,317	16,306
Amortization of deferred financing costs	526	171	2,732	3,905
Amortization of debt (premium) discount	(4,512)	—	—	468
Equity-based compensation expense	22,025	—	—	—
Exploratory dry hole expense	1,954	—	2,500	419
Expired leases	24,101	4,575	9,125	11,158
(Gain) loss on derivatives	10,247	(6,663)	(8,287)	40,460
Cash settlements of derivatives	(38,961)	(2,296)	4,117	88,689
Premium paid on derivatives	—	—	(520)	—
Loss on debt extinguishment	—	—	—	18,151
Interest converted into debt related to Founder notes	—	103	1,209	1,209
Interest added to notes receivable from related party	(949)	(85)	(867)	(774)
(Gain) loss on sale of property and equipment	388	1,923	22,179	(3,542)
Gain on acquisitions of oil and gas properties	—	—	(3,294)	—
Impact on cash from changes in:				
Accounts receivable	18,011	(21,184)	(43,530)	(10,500)
Other receivables	(4,045)	(662)	6,519	10,465
Receivables from related party	(11,468)	(117)	218	45
Prepaid expenses and other non-current assets	11,149	(591)	(6,203)	(819)
Advances from related party	(37,668)	24,116	(19,138)	42,528
Settlement of asset retirement obligations	(1,610)	(63)	(6,409)	(2,125)
Accounts payable to related party	—	—	(2,170)	—
Accounts payable, accrued liabilities and other liabilities	(41,463)	23,857	34,857	(11,493)
Cash from operating activities	86,809	26,336	59,328	131,704
Cash flows from investing activities:				
Capital expenditures	(762,760)	(36,695)	(313,961)	(214,061)
Acquisitions, net of cash acquired	(823,778)	(1,218)	(55,605)	(11,527)
Proceeds withdrawn from Trust Account	1,042,742	—	—	—
Contribution to equity method investment and other	(17,063)	—	(1,515)	—
Proceeds from sale of assets	312	—	25,205	1,290
Cash from investing activities	(560,547)	(37,913)	(345,876)	(224,298)
Cash flows from financing activities:				
Proceeds from long-term debt borrowings	431,500	60,000	373,065	722,557

Repayments of long-term debt	(273,565)	(43,000)	(296,622)	(921,034)
Deferred financing costs paid	(3,722)	—	(398)	(13,747)
Purchase and retirement of Class A common shares	(14,750)	—	—	—
Capital distributions	—	(68)	—	—
Capital contributions	—	—	207,875	303,462
Proceeds from issuance of Class A shares	400,000	—	—	—
Repayment of sponsor note	(2,000)	—	—	—
Repayment of deferred underwriting compensation	(36,225)	—	—	—
Redemption of Class A common shares	(33)	—	—	—
Cash from financing activities	501,205	16,932	283,920	91,238
Net increase (decrease) In cash, cash equivalents and restricted cash	27,467	5,355	(2,628)	(1,356)
Cash, cash equivalents and restricted cash, beginning of period	388	4,990	7,618	8,974
Cash, cash equivalents and restricted cash, end of period	$ 27,855	$ 10,345	$ 4,990	$ 7,618

The accompanying notes are an integral part of these financial statements.

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ALTA MESA RESOURCES, INC.
CONSOLIDATED STATEMENT OF CHANGES IN STOCKHOLDERS' EQUITY (Successor)
(in thousands)

?	Common Stock								Total		
?	Class A		Class B		Class C		Paid-In	Accumulated	Stockholders'	Noncontrolling	Total
?	Shares	Amount	Shares	Amount	Shares	Amount	Capital	Deficit	Equity	Interests	Equity
Balance at February 8, 2018	3,862	$ —	25,875	$ 3	—	$ —	$ 3,106	$ (8,114)	$ (5,005)	$ —	$ (5,005)
Conversion of common shares from Class B to Class A at closing of Business Combination	25,875	3	(25,875)	(3)	—	—	—	—	—	—	—
Class A common shares released from possible redemption	99,638	10	—	—	—	—	996,374	—	996,384	—	996,384
Class A common shares redeemed	(3)	—	—	—	—	—	(33)	—	(33)	—	(33)
Sale of Class A common shares	40,000	4	—	—	—	—	399,996	—	400,000	—	400,000
Class C common shares issued in connection with the closing of the Business Combination	—	—	—	—	213,402	21	(21)	—	—	—	—
Noncontrolling interest in SRII Opco issued in the Business Combination	—	—	—	—	—	—	—	—	—	2,058,635	2,058,635
Balance at February 9, 2018	169,372	17	—	—	213,402	21	1,399,422	(8,114)	1,391,346	2,058,635	3,449,981
Additional Class C common shares issued in connection with the settlement of the purchase consideration in the business combination	—	—	—	—	1,109	—	—	—	—	—	—
Noncontrolling interest in SRII Opco assumed in the business combination	—	—	—	—	—	—	—	—	—	8,758	8,758
Redemption of noncontrolling interests and Class C common shares for Class A common shares	12,341	1	—	—	(12,341)	(1)	105,593	—	105,593	(105,599)	(6)
Purchase and retirement of Class A common shares and related sale of SRII Opco Common Units	(3,102)	—	—	—	—	—	(25,589)	—	(25,589)	10,839	(14,750)
Restricted stock awards vested	1,944	—	—	—	—	—	2,465	—	2,465	(2,465)	—
Equity-based compensation expense	—	—	—	—	—	—	22,025	—	22,025	—	22,025
Shares withheld/retired for taxes on equity awards	(483)	—	—	—	—	—	(534)	—	(534)	—	(534)
Net loss	—	—	—	—	—	—	—	(1,524,699)	(1,524,699)	(1,724,648)	(3,249,347)
Balance at December 31, 2018	180,072	$ 18	—	$ —	202,170	$ 20	$1,503,382	$(1,532,813)	$ (29,393)	$ 245,520	$ 216,127

The accompanying notes are an integral part of these financial statements.

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ALTA MESA RESOURCES, INC.
CONSOLIDATED STATEMENTS OF CHANGES IN PARTNERS' CAPITAL (Predecessor)
(in thousands)

?		Predecessor
Balance, December 31, 2015	$	(177,049)
Contributions		377,076
Net loss		(167,921)
Balance, December 31, 2016		32,106
Contributions		200,000
Net loss		(77,661)
Balance, December 31, 2017		154,445
Distribution of non-STACK oil and gas assets, net of associated liabilities		43,482
Net loss		(14,862)
Balance, February 8, 2018	$	183,065

The accompanying notes are an integral part of these financial statements.

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ALTA MESA RESOURCES, INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
DECEMBER 31, 2018

NOTE 1 — DESCRIPTION OF BUSINESS

Alta Mesa Resources, Inc., together with its consolidated subsidiaries ("we" or "the Company"), is an independent exploration and production company focused on the acquisition, development, exploration and exploitation of unconventional onshore oil and natural gas reserves in the eastern portion of the Anadarko Basin in Oklahoma. We operate in two reportable business segments - Upstream and Midstream. Alta Mesa Holdings, LP ("Alta Mesa") conducts our Upstream activities and owns our proved and unproved oil and gas properties located in an area of the Anadarko Basin commonly referred to as the STACK. We generate upstream revenue principally by the production and sale of oil, gas and NGLs. We also operate in the Midstream segment through Kingfisher Midstream, LLC ("KFM"). KFM has a gas and oil gathering network, a cryogenic gas processing plant with offtake capacity, field compression facilities and a produced water disposal system in the Anadarko Basin that generate revenue primarily through long-term, fee-based contracts. The KFM assets are integral to our Upstream operations, which we conduct in the same region, and they are strategically positioned to provide similar services to other producers in the area.

We were originally incorporated in Delaware in November 2016 as a special purpose acquisition company under the name Silver Run Acquisition Corporation II for the purpose of effecting a merger, exchange, acquisition, purchase, reorganization or similar business combination involving it and one or more businesses.

On March 29, 2017, we consummated our initial public offering ("IPO") generating net proceeds of approximately$1.035 billion, and we completed the private sale of 15,133,333 warrants (the "Private Placement Warrants") to Silver Run Sponsor II, LLC (the "Sponsor") for$22.7 million. Proceeds from the IPO were placed in a trust account in 2017 to be held until an acquisition was completed.The trust account, plus interest earned, was utilized to fund a business combination (the "Business Combination") on February 9, 2018 in which the interests in Alta Mesa, Alta Mesa Holdings GP, LLC ("Alta Mesa GP") and KFM were acquired through a newly formed subsidiary, SRII Opco, LP ("SRII Opco").

In connection with the closing of the Business Combination, Alta Mesa distributed its non-STACK oil and gas assets and liabilities to High Mesa Holdings, LP (the "AM Contributor"), and we changed our name from "Silver Run Acquisition Corporation II" to "Alta Mesa Resources, Inc." and continued the listing of our Class A Common Stock and public warrants (sold as part of the shares issued in our IPO) on NASDAQ under the symbols "AMR" and "AMRWW," respectively.

NOTE 2 — SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Accounting and Presentation

These financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP"). We had no items of other comprehensive income during any period presented. Certain prior-period amounts in the consolidated financial statements have been reclassified to conform to the current-year presentation, but had no impact on net income (loss), stockholders' equity or partners' capital.

As a result of the Business Combination, we are the acquirer for accounting purposes and Alta Mesa and KFM are the acquirees. The identifiable assets acquired and liabilities assumed were recorded at their estimated fair values, which were pushed down to each entity.As a result, our financial statements and certain footnotes separate our presentation into two distinct periods, the periods before the consummation of the Business Combination ("Predecessor Periods") and the period after that date (the "Successor Period"). Our financial statements reflect Alta Mesa as the "Predecessor" for periods prior to the Business Combination. The Company is the "Successor" for periods after the Business Combination, reflecting the consolidation of Alta Mesa and KFM beginning on February 9, 2018. The period January 1, 2018 to February 8, 2018 is referred to as the 2018 Predecessor Period.

As noted above, we distributed our remaining non-STACK oil and gas assets and liabilities to the AM Contributor just prior to the closing of the Business Combination. We have determined that the remaining non-STACK oil and gas assets and liabilities as well as our Weeks Island field sold during the 4th quarter of 2017 are discontinued operations during the Predecessor Periods and have segregated their financial information from ours in the financial statements.

Principles of Consolidation

The consolidated financial statements include the accounts of the Company and its subsidiaries, and eliminate all intercompany transactions and balances. The Company's interests in oil and gas upstream ventures and partnerships are proportionately consolidated. Noncontrolling interest ("NCI") represents third-party ownership interests in SRII Opco and is presented as a component of equity.The portion of SRII Opco earnings that are not attributable to the Company are separately presented in our statement of operations.

Segment Reporting (Successor)

We operate in two reportable business segments: (i) Upstream and (ii) Midstream. Alta Mesa conducts our Upstream activities and owns proved and unproved oil and gas properties. KFM operates our Midstream segment as the owner and operator of gas gathering, processing and produced water disposal assets and crude oil gathering and transportation assets. Both segments are conducted in the United States and all revenue is derived from customers located in the United States.

Use of Estimates

Preparation of financial statements in conformity with GAAP requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements and the reported revenue and expenses during the reporting period. Estimates of reserves and their value are used to determine depletion and to conduct impairment analysis of oil and gas properties and can significantly affect future estimated cash flows utilized to assess goodwill and intangible assets for impairment.Estimating reserves has inherent uncertainty, including the projection of future rates of production and the timing of development expenditures.

Other estimates are utilized to determine amounts reported under GAAP related to collectibility of receivables, asset retirement obligations, derivatives, accounting for business combinations, federal and state taxes, share-based compensation and contingencies. We base certain of our estimates on historical experience and various other assumptions that we believe to be reasonable. We review estimates and underlying assumptions on a regular basis. Actual results may differ from these estimates.

Cash and Cash Equivalents

We consider all highly liquid investments purchased with an original maturity of three months or less to be cash equivalents. The Company regularly maintains cash balances that exceed federally insured amounts, but we have experienced no losses associated with these amounts. As of December 31, 2018, and 2017, we did not have any assets classified as cash equivalents.

Restricted Cash

Cash balances that are legally, contractually or otherwise restricted as to withdrawal or usage are considered restricted cash. As ofDecember 31, 2018, and 2017, our restricted cash represents cash received for production where the final division of ownership is in dispute or there is unclaimed property for pooling orders in Oklahoma.

Accounts Receivable

Our receivables arise primarily from (i) the sale of our production, (ii) joint interest owners' portion of operating costs for properties in which we are the operator, and (iii) for midstream services provided to third-party customers. The purchasers of our production and our midstream customers are concentrated in the oil and gas industry and therefore they are similarly affected by prevailing industry conditions. Accounts receivable are generally not collateralized. We may have the ability to withhold future revenue disbursements to recover non-payment of joint interest billings on properties we operate and market the production.

We routinely assess the recoverability of our receivables to determine their collectibility. We establish a valuation allowance to reduce receivables to their estimated collectible amounts, based upon several factors including, our historical experience, the length of time a receivable has been outstanding, communication with customers and the current and projected financial condition of specific customers.

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Property, Plant and Equipment

Our oil and gas property is accounted for using the successful efforts method under which lease acquisition costs and all development costs, including unsuccessful development wells, are capitalized.

Unproved Properties — Costs associated with the acquisition of leases are capitalized as incurred. These costs consist of amounts to obtain a mineral interest or right in a property, including related broker and other fees.These costs are classified as unproved until proved reserves are recognized, at which time the related costs are transferred to proved oil and gas properties and become subject to depletion, or when leases are impaired, at which time the costs are expensed as exploration costs. Unproved properties are not subject to depletion.

Proved Oil and Gas Properties — We capitalize costs incurred to drill, complete and equip proved reserves. Proved property costs include all costs incurred to drill and equip successful exploratory wells, development wells (regardless of success), development-type stratigraphic test wells and service wells, plus costs transferred from unproved properties.

Accounting policies for Midstream and other assets include:

Other Property, Plant and Equipment **—** Other property, plant and equipment, such as land, buildings, plant equipment, assets associated with produced water disposal, vehicles, office furniture and office equipment, are recorded at cost. Maintenance, repairs and minor renewals are expensed as incurred. Plant and equipment also includes costs for our cryogenic gas processing facility along with gas gathering pipelines and compression, including rights of way, and a crude oil gathering system and crude oil storage facility.

Other important accounting policies affecting property, plant and equipment include:

Depreciation and Depletion — Depletion of proved oil and gas properties is computed using the unit-of-production method based upon produced volumes and estimated proved reserves. Because all of our oil and gas properties are located in a single basin, we apply depletion on a single cost center. We deplete leasehold acquisition costs and the cost to acquire proved properties (generally proved undeveloped costs) based upon total estimated proved reserves. We deplete costs to drill, complete and equip wells plus the related lease costs (generally proved developed costs) over estimated proved developed reserves. Other non-oil and gas property and equipment is depreciated over their estimated useful lives, ranging from three to seven years.

We depreciate our Midstream property and equipment using the straight-line method over the estimated useful lives, which include35 years for our produced water disposal assets, processing plant and pipelines and 25 years for our compressors. Leasehold improvements are depreciated over the shorter of their useful lives or the term of the lease. Vehicles and office furniture and office equipment are depreciated over their estimated useful lives, ranging from three years to seven years.

Impairment — Because proved reserves have not been ascribed to unproved property, in determining whether it is impaired, we consider numerous factors including recent leasing activity, current development plans, recent drilling results in the area, our geologists' evaluation and the remaining lease term for the property. If a potential impairment exists, we develop a cash flow model based on estimated proved and unproved reserves and, combined with a market approach, estimate fair value. Our cash flow estimates for unproved reserves are reduced by additional risk-weighting factors. We then reduce the carrying amount, if higher, to estimated fair value.

We review proved oil and gas properties at least annually, or whenever events or changes in circumstances indicate that a potential impairment may have occurred. The determination of recoverability is based on comparing the estimated undiscounted future net cash flows to the carrying value. If the carrying amount exceeds the estimated undiscounted future net cash flows, we adjust the carrying amount of the properties to fair value, which we estimate by discounting the projected future cash flows using an appropriate risk-adjusted rate.

We evaluate whether the value of all other long-lived assets, including our midstream assets, is impaired when circumstances indicate the carrying value of those assets may not be recoverable. Such circumstances could result from events such as changes in the condition of an asset, changes to planned throughput or a change in our intent to utilize the asset. The determination of recovery is based on undiscounted cash flow projections compared to the carrying value of the assets. If the carrying amount exceeds undiscounted future net cash flows, we adjust the carrying amount of the assets to their estimated fair value. We assess the fair value of long-lived assets using commonly accepted techniques, and may use more than one method, including, but not

limited to, recent comparable sales, estimated replacement cost, an internally-developed, market participant-based discounted cash flow analysis or an analysis from outside professional advisors.

Exploration Expense

Exploration expenses, other than exploration drilling costs, are charged to expense as incurred. These expenses include seismic expenditures and other geological and geophysical costs, expired leases, delay rentals, gains or losses on settlement of asset retirement obligations and lease rentals. The costs of drilling exploratory wells and exploratory-type stratigraphic wells are initially capitalized pending determination of whether the well yields commercial reserves. If the exploratory well is determined to be unsuccessful, the cost is expensed as exploration expense in the period of that determination. If the exploratory well yields commercial reserves, it is transferred to proved oil and gas properties. Exploratory well costs may continue to be capitalized for several reporting periods if the assessment of commerciality is ongoing.

Equity Method Investment

We account for investments that we do not control, but in which we can exercise significant influence, using the equity method of accounting.Such investments are originally recorded at our acquisition cost. The investment is adjusted by our proportionate share of the investee's net income, increased by contributions made and decreased by distributions received. Our proportionate share of the investee's net losses throughDecember 31, 2018, was not material, but is included in "Other income (expense)" in our statement of operations.

We periodically assess the carrying value of our equity method investments for impairment when indicators exist indicating an impairment may be other-than-temporary. If an impairment is deemed to be other-than-temporary, we adjust the carrying value to fair value, if lower.

Deferred Financing Costs

Deferred financing costs reflect fees paid to lenders and third parties that are directly related to our establishment of our long term debt.The costs associated with the Alta Mesa RBL and KFM Credit Facility are reported as non-current assets and are amortized over the term of the facilities as additional interest expense. During the Predecessor Periods, costs associated with the issuance of our7.875% senior unsecured notes maturing in December 2024 (the "2024 Notes") were deferred as a reduction in the value of the outstanding debt and amortized as additional interest expense.

Acquisitions

Business combinations are accounted for using the acquisition method. The results of operations of any acquired businesses are included in our results of operations from the closing date. The total cost of each acquisition is allocated to tangible and intangible assets acquired and liabilities assumed based on their estimated fair values at the time of the acquisition.

Intangible Assets

In connection with the acquisition of KFM, we recognized the estimated fair value of acquired customer contracts and related customer relationships as intangible assets, which were valued using the income approach. These intangible assets, all of which relate to the Midstream segment, had finite lives and were subject to amortization utilizing an accelerated attrition method to approximate the benefit received over their economic lives. The weighted average amortization period for our intangible assets at December 31, 2018 was12 years.

We assess intangible assets for impairment when events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. In conducting our assessment of midstream intangible assets, we deemed them to be inseparable from the midstream tangible assets and assess them in the aggregate. If the aggregated value exceeds the estimated fair value, we recognize an impairment to reduce the intangible assets to their fair value.

Goodwill

Goodwill represents the excess of the purchase price over the estimated fair value of the identified assets and liabilities acquired.Goodwill is not amortized but is subject to periodic impairment assessment at least annually, or whenever events and circumstances indicate an impairment may exist. Impairment of goodwill is recognized as the amount by which a reporting

unit's carrying value exceeds its fair value, not to exceed the carrying amount of goodwill. Goodwill was recognized from the acquisition of KFM and allocated to the Midstream segment reporting unit. We had no goodwill prior to the Business Combination.

Asset Retirement Obligations

We recognize liabilities for the anticipated future costs of dismantlement and abandonment of our wells, facilities, and other tangible long-lived assets by increasing the carrying amount of the related long-lived asset at the time it is legally incurred. The fair values of new asset retirement obligations are estimated using expected future costs discounted to present value. The asset retirement cost is recognized as depletion or depreciation over the life of the asset. Accretion expense represents the increase to the discounted liability toward its expected settlement value and is included in "Depreciation, depletion and amortization" in the statements of operations. Asset retirement obligations are subject to revision primarily for changes related to the estimated timing and cost of abandonment.

There are no material legal or contractual obligations relating to dismantlement, decommissioning or removal of our Midstream assets, other than for certain of our produced water assets, for which asset retirement obligations have been established as of December 31, 2018.

Bond Premium on 2024 Notes

In connection with the Business Combination, we estimated the fair value of our $500.0 million 2024 Notes at $533.6 million. The excess fair value above the face value was recognized as a bond premium, which is being amortized as a reduction in interest expense over the remaining term of the notes.

Derivatives

We present our derivatives as assets or liabilities at estimated fair value. Changes in fair value of our derivatives, along with realized gains or losses from settlements, are recognized as "Gain (loss) on derivatives" in the statements of operations. Settlements of derivatives are classified as operating cash flows. Where master netting agreements are in place, we net the value of our derivative assets and liabilities with the same counterparty.

Income Taxes

Successor

Deferred income taxes are provided for the temporary differences between the basis of assets and liabilities for financial reporting and income tax purposes. We classify deferred tax assets and liabilities as noncurrent.

Tax positions meeting the more-likely-than-not recognition threshold are measured at the largest amount of benefit that is greater than 50% likely to be realized upon ultimate settlement, pursuant to the guidance set forth in ASC 740. We assess the ability to realize our deferred tax assets on a quarterly basis. Deferred tax assets may be reduced by a valuation allowance if it is more likely than not that some portion or all of the deferred tax assets will not be realized. A valuation allowance is established to reduce deferred tax assets to the amount expected to be realized when we determine that it is more likely than not that some or all of the deferred tax assets are not realizable.

We are also subject to the Texas margin tax, which is considered an income-based tax. We recognize tax (current and deferred) based on taxable income, as determined using the rules for the margin tax as a component of our income tax provision.

We assess uncertain tax positions using a two-step process. If we determine it is more likely than not that the income tax position will be sustained upon examination by the taxing authorities, we recognize the largest amount that is greater than 50% likely to be realized upon ultimate settlement. We have considered our exposure under the standard at both the federal and state tax levels. We did not record any liabilities for uncertain tax positions as of December 31, 2018 or December 31, 2017.

We record interest and penalties for the taxation, as a component of income tax expense. We did not incur any material tax interest or penalties for any period presented.

Alta Mesa's tax returns for the years ended December 31, 2015 and forward remain open for examination, but none are currently under examination by the relevant authorities.

Predecessor

Alta Mesa historically elected to be treated as an individual partnership for tax purposes. Accordingly, its items of income, expense, gains and losses flowed through to the partners and were taxed at the partner level. Accordingly, no tax provision for federal income taxes was recognized by the Predecessor.

Predecessor net income (loss) for financial statement purposes differed significantly from taxable income (loss) reported to limited partners as a result of differences between the tax bases and financial reporting bases of assets and liabilities and the taxable income allocation requirements under Alta Mesa's amended and restated partnership agreement. As a result, the aggregate difference in the basis of net assets for financial and tax reporting purposes could not be readily determined due to some tax basis differences being determined at the partner level and Alta Mesa's lack of information about each unitholder's tax attributes in Alta Mesa.

Revenue Recognition

Predecessor -

Oil, natural gas, and NGL revenue were recognized when production was sold to a purchaser at a fixed or determinable price, when delivery had occurred and title had transferred, and collectibility of the revenue was reasonably assured. During the Predecessor Periods, we followed the sales method of accounting for revenue. Under this method of accounting, revenue was recognized based on volumes sold. There were no material gas imbalances during the periods presented.

Successor (Upstream) -

In May 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2014-09, "Revenue from Contracts with Customers." This ASU and the associated subsequent amendments (collectively, "ASC 606"), superseded virtually all of the revenue recognition guidance under GAAP. The core principle of the five-step model is that an entity will recognize revenue when it transfers control of goods or services to customers at an amount that reflects the consideration to which it expects to be entitled in exchange for those goods or services. Effective December 31, 2018, we ceased to be an emerging growth company and adopted ASC 606 for the Successor Period, using a modified retrospective approach. There was no impact on the timing of recognition of revenue or of our classification of amounts between revenue and operating expenses upon adoption of ASC 606.

Our revenue from contracts with customers includes the sale of crude oil, natural gas, and NGLs. These sales are recognized as revenue when production is sold to a customer in fulfillment of performance obligations under the terms of the underlying contracts. Performance obligations primarily comprise delivery of our production at a delivery point, as negotiated within each contract. Each unit of oil, natural gas, and NGL is separately identifiable and represents a distinct performance obligation to which the transaction price is allocated.

Performance obligations are satisfied once control of the product has been transferred to the customer. We consider a variety of facts and circumstances in assessing the point control is transferred, including but not limited to: whether the purchaser can direct the use of the hydrocarbons, the transfer of significant risks and rewards, our right to payment, and transfer of legal title.

Our oil production is primarily sold under market-sensitive contracts that are typically priced at a differential to the NYMEX price or at purchaser posted prices for the producing area. For oil contracts, we record sales and related expenses on a gross basis upon satisfaction of our performance obligations.

Our natural gas production is primarily sold to purchasers at prevailing market prices. We evaluate the contract terms of our gas processing arrangements to determine whether the processor is a service provider or a customer on a contract by contract basis based on the assessment of control and, when applicable, principal versus agent guidance under ASC 606. During the Successor Period, we determined that we controlled the products during processing (i.e., control transfers at the tailgate of the processing plant) or until the processor's sale to the end customers in downstream markets (i.e., the processor is our agent and we are the principal selling party). Accordingly, we record the sale of natural gas and NGLs and applicable gathering, processing, transportation and fractionation fees on a gross basis at the time the product is delivered to the customer and the

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gathering and processing services are rendered, similar to the accounting treatment required under previous revenue accounting guidance.All facts and circumstances are considered and judgment is often required in making this determination.

Customers are invoiced once our performance obligations have been satisfied. Payment terms and conditions vary by contract type, although terms generally include a requirement of payment within 30-60 days. There are no significant judgments that affect the amount or timing of revenue from contracts with customers. Accordingly, our product sales contracts do not give rise to material contract assets or contract liabilities, apart from production receivables.

Our receivables consist mainly of receivables from oil and natural gas purchasers and from joint interest owners on properties the Company operates, as well as for unbilled costs for wells subject to Oklahoma's forced pooling process in which mineral owners have the option to participate in the drilling of pooled wells. Depending on the mineral owner's decision, these costs will be billed to them or added to our oil and gas properties. Accounts receivable are stated at the historical carrying amount net of write-offs and an allowance for doubtful accounts.

We have concluded that disaggregating revenue by product type appropriately depicts how the nature, amount, timing, and uncertainty of revenues and cash flows are affected by economic factors and have reflected this disaggregation of revenue for all periods presented.

We do not have material unsatisfied performance obligations for contracts as all contracts have either an original expected length of one year or less or the entire future consideration is variable and allocated entirely to a wholly unsatisfied performance obligation.

Midstream -

We have the following significant revenue sources each of which we consider to be a distinct service and each of which possesses a single performance obligation:

- Natural gas gathering, processing and sale of NGLs and residue gas for Alta Mesa and third parties;
- Crude oil gathering for Alta Mesa; and
- Produced water gathering and disposal for Alta Mesa and third parties.

We provide our services pursuant to a variety of contracts that set forth our fees, including in certain contracts, the percentage of the proceeds from the sale of our customers' products in addition to the specified fee. Our services are typically billed on a monthly basis in the month following services or delivery of the product with payment typically due within 30 days. We do not offer extended payment terms and we have no contracts with financing components. Our gathering contracts have initial terms that span multiple years up to the life of the dedicated properties.Our most significant produced water contract has an initial term of 15 years.

We recognize revenues principally under contracts that contain one or more of the following arrangements:

Fee-based arrangements

Revenue for fee-based arrangements are recognized over the contract term with revenue recognized for each month of service based on the volumes delivered by the customer. Both gas gathering and processing plus crude oil gathering services are recognized in gathering and processing revenues. Produced water services are recognized as produced water disposal fees.

For service rates that are unchanged over the contract term or escalate only due to inflation, we recognize revenue at the rate in effect during the month of service. We have instances where we also charge supplemental fees for only an early portion of the contract term and this revenue is recognized over the expected period of customer benefit, which is generally the remaining term of the contract.The difference between the amount billed and collected for such early term fees and the amount recorded as revenue is deferred and recognized as contract liabilities.At December 31, 2018, we have recognized a deferral of $1.7 million of limited term fees which is included in other long-term liabilities.

Percent-of-proceeds arrangements

Under our percent-of-proceeds arrangements, we generally receive natural gas from producers at or near the wellhead, move it through our gathering system, process it to separate the gas and liquid products and sell the resulting gas and NGLs to third parties. We then remit to the producers an agreed-upon percentage of the actual proceeds received from sales. The margins we earn are directly related to the volumes that flow through our system and the price at which we are able to sell the products.

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We evaluate our percent-of-proceeds arrangements with customers against the principal/agent provisions of the underlying contract. For those arrangements where we possess control of the commodity after processing and act as principal in the sale, we record sales revenue equal to the gross price received and we recognize the cost paid to the purchaser as cost of sales of gathered purchased production.For those percent-of-proceeds arrangements where we do not control the products after processing, because substantially all of the sales proceeds are paid to the producer, we act as an agent for the producer and only recognize the net margin that we earn within sales of gathered production.

In limited instances, we may also receive products as consideration under percent-of-proceeds agreements.We recognize revenue for the products received at their fair value in the month of service. During the period from February 9, 2018 through December 31, 2018, we recognized$0.6 million within gathering and processing revenue for such transactions.

Sale of gathered production

We sell gas, NGLs and condensate purchased from our customers to third parties pursuant to short term arrangements at market-based prices adjusted for location and quality differentials. These sales are recognized at the point (i) when we satisfy our performance obligation by transferring control of the product to the purchaser at the specified delivery point, (ii) when amounts are determinable and (iii) when we have determined that collectibility is probable. The determination of the point control is transferred relies upon a variety of facts and circumstances including: the purchaser's ability to use the products, the transfer of significant risks and rewards, our right to payment and transfer of legal title.The underlying cost to purchase the underlying products is recognized when we obtain control of the product, but is generally concurrent with their sale.

Also, we may sell products to other midstream companies pursuant to off-take agreements.Under these contracts, we evaluate whether we control the products during processing and whether the processor controls the products in their sale to ultimate purchaser.For those contracts where we do not control the products during processing, we recognize revenue on their sale to the midstream company based on the price received net of processing fees earned by the midstream company. For those contracts where we control the products during processing and and where we direct their sale, we recognize revenue on the gross price received within sales of gathered production and we recognize the fees paid to the midstream company as transportation, processing and marketing expense.

Equity-Based Compensation

We grant various types of stock-based awards, including stock options, restricted stock and performance-based restricted stock units to certain of our employees.

The fair value of stock option awards is determined using the Black-Scholes option pricing model, which includes various assumptions. Expected volatilities utilized in the option pricing model are based on the re-levered asset volatility implied by a set of comparable companies. Expected term is based on the simplified method, and is estimated as the average of the weighted average vesting term and the time to expiration as of the grant date. Dividend yield is based on our expectations of dividend payments during the expected term of the options granted and risk-free interest rates are based on U.S. Treasury rates in effect at the grant date.

Service-based restricted stock awards are valued using the market price of our Class A Common Stock on the grant date. Performance-based restricted stock awards are valued using the market price of Class A Common Stock at the later of grant date and when all performance-based criteria are determined.

We recognize the estimated fair value of stock option and restricted stock awards as compensation expense on a straight-line basis over the applicable vesting period, which generally is three years, except in the case of awards made to our directors, which vest immediately upon issuance. Awards of performance-based restricted stock units that contain tranches with multi-year performance targets are recognized over the vesting period for which performance criteria for each tranche have been determined. All awards to employees typically require continued employment to vest. Forfeitures of unvested awards are recognized when they occur and result in the reversal of previously recognized expense.

Fair Value Hierarchy

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date within our principal market.

There are three levels of the fair value hierarchy:

- *Level 1* — Fair value is based on quoted prices in active markets for identical assets or liabilities.
- *Level 2* — Fair value is determined using significant observable inputs, generally either quoted prices in active markets for similar assets or liabilities, or quoted prices in markets that are not active.
- *Level 3* — Fair value is determined using one or more significant inputs that are unobservable in active markets at the measurement date. Such inputs are often used in pricing models, discounted cash flow calculations, or similar techniques.

We utilize fair value measurements to account for certain items, determine certain account balances and provide disclosures. Fair value measurements are also utilized in assessing the impairment of long-lived assets.

We consider the book values of our cash, accounts and notes receivable and current liabilities to approximate fair value due to their short-term nature. We also consider the carrying value of our long-term debt under the Alta Mesa RBL and the KFM Credit Facility to not be materially different from fair value due to short-term variable market rates of interest applicable to our outstanding borrowings.

Earnings Per Share

Basic earnings per share is calculated by dividing earnings available to Class A common stockholders by the weighted average number of shares outstanding during each period. In periods where we report negative earnings, basic and diluted earnings per share are identical.

The Company uses the "if-converted" method to determine the potential dilutive effect of exchanges of outstanding SRII Opco Common Units and corresponding shares of its outstanding Class C Common Stock, as well as outstanding warrants and the treasury stock method to determine the potential dilutive effect of restricted stock, restricted stock units and stock options.

Going Concern

We are required to evaluate our ability to continue as a going concern for a period of one year following the date of issuance of our financial statements. As part of that evaluation, we took into consideration the following factors:

- During 2018, we incurred a net loss of $3.2 billion, due mainly to impairment of our proved and unproved oil and gas properties and the long-lived assets, intangible assets and goodwill of our Midstream segment. Also, at December 31, 2018, our current liabilities exceeded our current assets by approximately $813.5 million, including the recognition of $690.1 million of debt as current liabilities based upon the likelihood of failure to comply with covenants throughout 2019.
- Market prices for crude oil declined significantly during the fourth quarter of 2018, closing in the mid-$40 range at the end of 2018.This negatively impacted future estimated prices for oil in 2019 and beyond, which lowers our expected future economic results from our assets.
- Our 2018 drilling program, much of which involved the drilling of additional wells in close proximity to existing wells, did not meet our expectations for production and recovery. We also experienced an increasing gas-to-oil ratio as a well's production ages, which has contributed to a lowering of the expected economics of our properties.
- Our drilling costs increased in 2018 as compared to 2017 as a result of increased hydraulic fracturing intensity, installation of dewatering pumps, and the increasing number of stages completed in a lateral. While initially generating positive results, the benefit of these advanced completion techniques began to abate over time indicating limited long-term effect over the course of each well's life. Our capital expenditures during the Successor Period were considerably higher than during 2017 and 2016.
- On April 1, 2019, our borrowing base under the Alta Mesa RBL was reduced to $370.0 million. During April 2019, we drew $66.5 million to consume substantially all of the remaining capacity under the Alta RBL. In August 2019, the lenders exercised their ability to make an optional redetermination of our borrowing base ahead of the regular redetermination scheduled in October 2019, and via this redetermination, our borrowing base was reset to $200.0 million, effective August 13, 2019. As our combined borrowings and letters of credit outstanding exceed the new borrowing base amount by $162.4 million, we have five months to make ratable monthly payments of $32.5 million to cause utilization to be less than or equal to the borrowing base. If we are unable to make this repayment, we will be in

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default under the Alta Mesa RBL. There is a risk that future redeterminations could reduce the borrowing base further. Our decreased borrowing base could cause us to reduce or abandon our development activities.
- We may be unable to obtain covenant relief or to replace the Alta Mesa RBL with debt that would allow us to meet any attendant covenant requirements. Also, the lack of sufficient borrowing capacity may prevent us from maintaining our current levels of production, which could negatively impact our ability over time to service our debt and meet our other obligations.
- We anticipate having difficulty meeting our existing leverage covenants during the next 12 months following the issuance of these financial statements without relief from our lenders and may fail to satisfy the consolidated total leverage ratio covenant in the Alta Mesa RBL as early as the measurement date of September 30, 2019.
- We have $500.0 million of unsecured debt in the form of our 2024 Notes, with an interest payment of approximately$20.0 million due in December 2019. The 2024 Notes trade substantially below par value.
- We failed to timely provide the lenders under the KFM Credit Facility quarterly financial statements for the quarter ended December 31, 2018, and we failed to provide our lenders notice in connection with KFM's acquisition of the produced water assets from Alta Mesa, including the delivery of certain recorded instruments of transfer. In April 2019, we entered into an amendment and limited waiver (the "Amendment") to the KFM Credit Facility to waive the defaults and events of default arising or resulting from those failures.The Amendment adds provisions which limit the maximum amount of cash KFM can hold to$15.0 million. The Amendment also generally provides that any amendment to a material contract with an affiliate during a six-month period that causes a reduction to projected revenue by more than 15% constitutes an event of default. Should Alta Mesa be required to seek protection under laws governing bankruptcy within the next 12 months, we believe there is a risk that the courts could attempt to reject or alter its agreements with KFM in a manner that could cause KFM's consolidated revenues to be negatively impacted by more than 15%, which would constitute an event of default under the KFM Credit Facility and give our lenders the ability to accelerate repayment of all outstanding amounts.
- Our Class A common stock has been trading below $1.00 per share since February 22, 2019. On April 3, 2019, we were notified by NASDAQ that we are not in compliance with the minimum bid price requirement.Continued trading at these levels may put further pressure on the value of our common stock and limit our ability to raise additional capital in the equity markets.
- Our ability to collect receivables due from High Mesa and its affiliates.

The above factors raise substantial doubt about our ability to continue as a going concern. To address this, we have:

- retained financial advisors to assist in evaluating financial alternatives;
- engaged in discussions with the advisors for the Alta Mesa RBL lenders about obtaining covenant relief to address the future expected inability to satisfy the leverage requirement, however, it is currently expected that such relief would only be available in connection with a reduction in Alta Mesa's borrowing capacity which could further hamper our liquidity;
- considered seeking new sources of financing, however, such efforts do not appear to present a substantive solution; and
- engaged in discussions with and provided requested information to financial and legal advisors for group of holders of Alta Mesa's 2024 Notes, but we cannot predict what will result from the discussions or whether they will yield a constructive deal.

In light of the above, we believe substantial unresolved doubt exists regarding our ability to continue as a going concern for 12 months following the issuance of these financial statements. We have continued reporting the indebtedness under the KFM Credit Facility as noncurrent based upon the high probability of meeting the covenants throughout 2019, but we have reported all debt at Alta Mesa as current liabilities based upon our conclusions about prospective covenant compliance during 2019.

Recently Issued Accounting Standards Applicable to Us

Adopted

During the 1st quarter of 2018, we adopted Accounting Standards Update ("ASU") No. 2017-04,*Intangibles - Goodwill and Other, Simplifying the Test for Goodwill Impairment.* This new guidance removes Step 2 of the goodwill impairment test, which requires a hypothetical purchase price allocation. Accordingly, any identified impairment of goodwill will be recognized as the amount by which a reporting unit's carrying value exceeds its fair value, not to exceed the carrying amount of goodwill. We utilized this standard to conduct impairment analysis following its adoption including determining the amount of impairment expense recorded in 2018.

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We adopted ASU No. 2016-15, *Statement of Cash Flows: Classification of Certain Cash Receipts and Cash Payments*("ASU 2016-15") on December 31, 2018, which clarified how certain transactions are classified in the statement of cash flows.The adoption of this guidance had no material effect.

We adopted ASU 2014-09, *Revenue from Contacts with Customers*, and related amendments, codified as Accounting Standards Codification ("ASC") 606, on December 31, 2018, retroactive to the beginning of our Successor Period.The impact of adoption of this standard is more fully described below.

Not Yet Adopted

Leasing Standards

In February 2016, the FASB issued ASU No. 2016-02,*Leases* (Topic 842) ("ASU 2016-02"), which requires that lessees recognize a lease liability, which is a lessee's discounted obligation to make payments under a lease and a right-of-use asset, arising from a lessee's right to use an asset over the lease term. We have used a modified retrospective transition approach to apply the standard as of January 1, 2019, the date of our adoption.

In January 2018, the FASB issued ASU No. 2018-01,*Land easement practical expedient for transition to Topic 842* ("ASU 2018-01"), which provides an optional transition practical expedient to not evaluate under Topic 842 existing or expired land easements that were not previously accounted for as leases under Topic 840, Leases. ASU 2018-01 and subsequent applicable ASUs also provide several other optional practical expedients in transition. We elected the "package of practical expedients", which permits us to forgo reassessment of our prior conclusions about lease identification, lease classification and initial direct costs for leases entered into prior to the effective date, January 1, 2019. We also elected the land easement relief which permits us to forgo reassessment of existing or expired land easements not previously accounted for under ASC 840. Additionally, we elected the practical expedient to not provide comparative reporting periods and therefore financial information will not be updated and the disclosures required under the new standard will not be provided for dates and periods before January 1, 2019.By accounting policy, we will not separate non-lease components from lease components and we elected the short-term lease recognition exemption for classes of underlying assets. We did not elect the use-of-hindsight practical expedient.

At adoption, we recognized operating lease right of use assets and operating lease liabilities of$15 million each. There was no adjustment to retained earnings upon adoption.

Other Standards

In June 2016, the FASB issued ASU No. 2016-13,*Financial Instruments - Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments*. This standard requires the use of a new "expected credit loss" impairment model rather than the "incurred loss" model we use today. With respect to our trade receivables and certain other financial instruments, we may be required to (i) maintain and use lifetime loss information rather than annual loss data and (ii) forecast future economic conditions and quantify the effect of those conditions on future expected losses.The standard, including related amendments, which will be effective for us on January 1, 2020, also requires additional disclosures regarding the credit quality of our trade receivables and other financial instruments. No determination has yet been made of the impact of this new standard on our financial position or results of operations.

In August 2018, the FASB issued ASU No. 2018-15,*Intangibles - Goodwill and Other - Internal-Use Software (Topic 350-40): Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That Is a Service Contract*("ASU 2018-15"). The amendments in this standard align the requirements for capitalizing implementation costs incurred in a hosting arrangement that is a service contract with the requirements for capitalizing implementation costs incurred to develop or obtain internal use software (and hosting arrangements that include an internal-use software license). Under this new standard, a customer in a hosting arrangement that is a service contract is required to follow the guidance in Subtopic 350-40 to determine which implementation costs to capitalize as a prepaid asset related to the service contract and which costs to expense. The capitalized implementation costs are to be expensed over the term of the hosting arrangement and reflected in the same line in the consolidated statement of operations as the fees associated with the hosting element of the arrangement. Similarly, capitalized implementation costs are to be presented in the statement of cash flows in the same line as payments made for fees associated with the hosting element. We will adopt this new standard no later than January 1, 2020, although early adoption is permitted. We are currently evaluating the impact of this new standard on our consolidated financial position and results of

operations and have not yet determined when to adopt and whether to apply the new standard retrospectively or prospectively to implementation costs incurred after the date of adoption.

In August 2018, the FASB issued ASU No. 2018-13, *Fair Value Measurement (Topic 820) Disclosure Framework - Changes to the Disclosure Requirements for Fair Value Measurement* ("ASU 2018-13"), which modifies the disclosure requirements of fair value measurements. ASU 2018-13 is effective for us beginning January 1, 2020. Certain disclosures are required to be applied on a retrospective basis and others on a prospective basis. We don't expect the adoption of this standard to impact our financial position or results of operations.

NOTE 3 — ADOPTION OF NEW STANDARD - REVENUE FROM CONTRACTS WITH CUSTOMERS

We were previously an "emerging growth company", which allowed us to defer adoption of ASC 606, *Revenue from Contracts with Customers*, until 2019. However, as of December 31, 2018, we became a large accelerated filer. Accordingly, we were required to adopt ASC 606, retroactive to the beginning of our 2018 Successor Period, using the modified retrospective method under which only the Successor Period is adjusted for the application of the new rules.

Because we adopted this new standard effective as of the beginning of our Successor Period, the implementation of this standard did not result in a cumulative-effect adjustment on date of adoption. There was no impact from adoption on the timing or classification of our Upstream segment's results of operations, however, it did impact the timing and classification of our Midstream segment's revenue and associated costs related to certain gas processing contracts as follows.

- Previously, gathering and processing fee revenue was recognized based on the rates in effect for the month of service, even when certain fees were charged on an upfront or a limited-term basis. Under ASC 606, if a fee is unchanged over the contract term or if it escalates only due to inflation, revenue is recognized based on the rate in effect. However, revenue associated with limited-term fees are partially deferred and recognized over the expected period of customer benefit, which is generally the remaining term of the contract with that customer. This results in a change in the timing of revenue recognition for the limited-term fee. Accordingly, the up-front fees collected, which would have been recognized at point of billing under the previous rules, are now recognized over a longer term, which resulted in a deferral of $1.7 million of revenue as of December 31, 2018.

- Previously, we recognized expense when we purchased a customer's production and we recognized revenue when the product met the criteria for sale to a third party. In such instances, if all or a significant percentage of the proceeds from the sale must be returned to the producer, we now are deemed to be an agent. Accordingly, the purchase and sale are now presented as a net transaction with our margin included in gathering and processing revenue. This results in a reduction in product sales revenue and elimination of product costs with no changes to operating income or net income.

  For noncash consideration received for services in percent-of-proceeds agreements, we previously recognized revenue only upon the sale of our portion of the related products retained for those services. We now recognize revenue for the products received as noncash consideration in exchange for the services provided and revenue from product sales is recognized, along with product expense related to the sale, when the product meets the criteria for sale to a third party. This results in an increase in gathering and processing revenue and an increase in product costs with no changes to operating income or net income.

The following tables summarize the impact to our revenue and costs following adoption of ASC 606, effective at the beginning of the period:

(in thousands)?	As now reported: February 9, 2018 Through March 31, 2018	Three Months Ended June 30, 2018	September 30, 2018	December 31, 2018	Total period
Revenue:					
Sales of gathered production	$ 3,873	$ 8,924	$ 9,129	$ 9,580	$ 31,506
Midstream revenue	3,260	6,817	7,802	9,581	27,460
All other revenue	33,885	66,459	122,873	185,794	409,011
Total revenue	41,018	82,200	139,804	204,955	467,977
Operating Expenses:					
Cost of sales for purchased gathered production	3,809	8,902	9,461	9,075	31,247
Transportation, processing and marketing	3,359	5,396	5,181	5,357	19,293
All other expenses	66,580	83,404	94,268	3,381,354	3,625,606
Total operating expenses	73,748	97,702	108,910	3,395,786	3,676,146
Income (loss) from operations	$ (32,730)	$ (15,502)	$ 30,894	$ (3,190,831)	$ (3,208,169)

As the adoption of ASC 606 occurred effective with the beginning of our Successor Period, there was no impact on the timing or classification of our revenue or associated costs with regard to our Predecessor reporting covering the period from January 1, 2018 to February 8, 2018, nor was there an impact for the Predecessor to 2017 and 2016 due to our method of adoption.

(in thousands)?	As previously reported: February 9, 2018 Through March 31, 2018	Three Months Ended June 30, 2018	September 30, 2018	December 31, 2018	Adjustment to reflect adoption of ASC 606	Total period under ASC 606
Revenue:						
Sales of gathered production	$ 8,369	$ 19,605	$ 22,676	$ 25,648	$ (44,792)	$ 31,506
Midstream revenue	3,411	7,073	8,102	9,902	(1,028)	27,460
All other revenue	34,090	66,459	122,873	185,589	—	409,011
Total revenue	45,870	93,137	153,651	221,139	(45,820)	467,977
Operating Expenses:						
Cost of sales for purchased gathered production	$ 8,220	$ 19,383	$ 22,830	$ 24,950	$ (44,136)	$ 31,247
Transportation, processing and marketing	3,359	5,413	5,181	5,357	(17)	19,293
All other expenses	66,755	83,404	94,268	3,381,179	—	3,625,606
Total operating expenses	78,334	108,200	122,279	3,411,486	(44,153)	3,676,146
Income (loss) from operations	$ (32,464)	$ (15,063)	$ 31,372	$ (3,190,347)	$ (1,667)	$ (3,208,169)

NOTE 4 — IMPAIRMENT OF ASSETS

Successor	Predecessor

(in thousands)	February 9, 2018 Through December 31, 2018	January 1, 2018 Through February 8, 2018	Year Ended December 31, 2017	Year Ended December 31, 2016
Upstream				
Impairment of unproved properties	$ 742,065	$ —	$ —	$ 16
Impairment of proved properties	1,291,647	—	1,188	366
Total Upstream impairment of assets	2,033,712	—	1,188	382
Midstream				
Impairment of Cimarron investment	15,963	—	—	—
Impairment of property, plant and equipment	68,407			
Impairment of intangible assets	394,999	—	—	—
Impairment of goodwill	691,970	—	—	—
Total Midstream impairment of assets	1,171,339	—	—	—
Total impairment of assets	$ 3,205,051	$ —	$ 1,188	$ 382

During the late fourth quarter of 2018, we experienced a combination of depressed prevailing oil and gas prices, changes to assumed spacing in conjunction with evolving views on the viability of multiple benches and reduced individual well expectations. We determined these factors indicated possible impairment of our assets. Following our analysis of impairment, we recognized impairment charges of$2.0 billion to our proved and unproved oil and gas properties using an income approach supplemented by a market approach for our unproved properties.

Impairment of equity method investment

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As the outlook for Alta Mesa volumes and third-party volume opportunities in the area were significantly lower than initially projected, we suspended future contributions to Cimarron Express Pipeline, LLC ("Cimarron") and have begun discussions to abandon the project.We do not believe the project will be completed and we conducted an impairment analysis resulting in recognition of an impairment charge to reduce the carrying value of our investment in Cimarron to its estimated fair value atDecember 31, 2018.

Impairment of property, plant and equipment and intangible assets

We performed a quantitative assessment of our property, plant and equipment and intangible assets, which included the use of an income approach which determined that the future undiscounted cash flows associated with our Midstream long-lived assets and intangible assets were below the combined carrying value of those assets. The cash flows used in the income approach were largely determined based on expected future gathering volumes which are dedicated to our gathering and processing facilities and are considered Level 3 inputs. We also considered the overall utilization of the processing plant and applied downward adjustments to the cost approach to account for decreased plant utilization. Based on an estimate of fair value using a discounted cash flow income approach, we determined that the carrying value of our Midstream property, plant and equipment was in excess of its fair value and that the intangible assets were fully impaired atDecember 31, 2018. Accordingly, we recognized impairment charges of $68.4 million to reduce the carrying value of our Midstream property, plant and equipment to fair value and $895 million to reduce the remaining carrying value of our intangible assets to zero.

Impairment of goodwill

We performed a quantitative assessment to determine if the goodwill attributable to the Midstream segment was impaired as ofDecember 31, 2018. Our assessment included the use of (i) an income approach to calculate the present value of estimated future discounted cash flows and (ii) a market approach to assess the value of the Midstream segment based on market participant multiples applied to the segment's 2019 estimated EBITDA. The cash flows used in the income approach were largely determined based on expected future production volumes of our Upstream segment, much of which is dedicated to the Midstream segment's gathering and processing facilities.The income approach also used a market participant-based discount rate. Each of our assumptions regarding earnings, cash flows and discount rates are based mainly on Level 3 unobservable inputs. The results from the income approach and the market approach were appropriately weighted to recognize an impairment charge to eliminate the remaining carrying value of our goodwill.

NOTE 5 — RECEIVABLES

?	Successor	Predecessor
(in thousands)?	**December 31, 2018**	**December 31, 2017**
Production and processing sales and fees	$ 51,004	$ 26,916
Joint interest billings	18,147	13,821
Pooling interest [1]	18,786	35,839
Allowance for doubtful accounts	(95)	(415)
Total accounts receivable, net	$ 87,842	$ 76,161

(1) Pooling interest relates to Oklahoma's forced pooling process which permits mineral interest owners the option to participate in the drilling of proposed wells. The pooling interest listed above represents unbilled costs for wells where the option remains pending. Depending upon the mineral owner's decision, these costs will be billed to them or added to oil and gas properties.

Activity in our allowances for doubtful accounts for trade and related party receivables was as follows:

?	Successor	Predecessor		
(in thousands)?	February 9, 2018 Through December 31, 2018	January 1, 2018 Through February 8, 2018	Year Ended December 31, 2017	Year Ended December 31, 2016
Trade receivables:				
Balance at beginning of period	$ 415	$ 415	$ 490	$ 1,030
Charged to expense	25	—	(69)	243
Deductions	(345)	—	(6)	(783)
Balance at end of period	$ 95	$ 415	$ 415	$ 490
Related party receivables:				
Balance at beginning of period	$ —	$ —	$ —	$ —
Charged to expense[(1)]	22,438	—	—	—
Deductions	—	—	—	—
Balance at end of period	$ 22,438	$ —	$ —	$ —

(1) At December 31, 2018, receivables, including notes receivable, from HMI were approximately $23.4 million. Following receipt of approximately $1.0 million in 2019, the balance was reduced to $22.4 million. Because HMI disputes its obligations under the promissory notes with us and challenges other amounts due to us, we established an allowance for doubtful accounts totaling 22.4 million, which is included in general and administrative expense in 2018.

NOTE 6 — EARNINGS PER SHARE

?	Successor
(in thousands, except shares and per share data)	February 9, 2018 Through December 31, 2018
Net loss attributable to AMR Class A common stockholders	$ (1,524,699)
?	
Weighted average Class A common shares outstanding (Basic)	175,151,969
Effect of dilutive securities:	
Class A shares assumed issued to holders of noncontrolling interests upon redemption	—
Weighted average common shares outstanding (Diluted)	175,151,969
?	
Loss per common share attributable to AMR common stockholders:	
Basic and diluted	$ (8.71)

During the Successor Period, approximately 99.9 million shares of Class C Common Stock, 63.0 million of warrants and 6.2 million of aggregate stock options, restricted stock and restricted stock units, were excluded from the calculation of diluted earnings per share as their effect would have been anti-dilutive.

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NOTE 7 — SUPPLEMENTAL CASH FLOW INFORMATION

?	Successor	Predecessor		
(in thousands)?	February 9, 2018 Through December 31, 2018	January 1, 2018 Through February 8, 2018	Year Ended December 31, 2017	Year Ended December 31, 2016
Supplemental cash flow information:				
Cash paid for interest	$ 52,017	$ 1,145	$ 47,773	$ 74,694
Cash paid for income taxes	1,573	—	—	285
Non-cash investing and financing activities:				
Increase in asset retirement obligations	5,665	—	4,363	2,719
Asset retirement obligations assumed on purchased properties	—	—	702	—
Increase in accruals or payables for capital expenditures	39,997	4,896	71,995	12,375
Increase in accounts payable to related party for capital expenditures	—	—	7,646	—
Increase in withholding tax accruals for share-based compensation	534	—	—	—
Distribution of non-STACK assets, net of liabilities	—	43,482	—	—
Equity issued in Business Combination	2,067,393	—	—	—
Release of Common stock from possible redemption	996,384	—	—	—
Redemption of noncontrolling interests in SRII Opco for Class A common shares and other	(6)	—	—	—
Contribution of interests in oil and gas properties	—	—	—	65,740
Contribution receivable	—	—	—	7,875

The following table summarizes cash, cash equivalents and restricted cash in the statements of cash flows:

?	Successor	Predecessor		
(in thousands)?	December 31, 2018	February 8, 2018	December 31, 2017	December 31, 2016
Cash and cash equivalents	$ 26,854	$ 9,070	$ 3,660	$ 7,102
Restricted cash	1,001	1,275	1,269	433
Cash from discontinued operations	—	—	61	83
Total cash, cash equivalents and restricted cash	$ 27,855	$ 10,345	$ 4,990	$ 7,618

NOTE 8 — SIGNIFICANT ACQUISITIONS AND DIVESTITURES

2018 Activity

On February 9, 2018 (the “Closing Date”), we consummated the transactions contemplated by (i) the Contribution Agreement (“AM Contribution Agreement”), dated August 16, 2017, with Alta Mesa, the AM Contributor, High Mesa Holdings GP, LLC, the sole general partner of the AM Contributor, Alta Mesa GP, and, solely for certain provisions therein, the equity owners of the AM Contributor, (ii) the Contribution Agreement (the “KFM Contribution Agreement”), dated August 16, 2017, with KFM Holdco, LLC, a Delaware limited liability company (the “KFM Contributor”), Kingfisher Midstream, LLC, and, solely for certain provisions therein, the equity owners of the KFM Contributor; and (iii) the Contribution Agreement (“the Riverstone Contribution Agreement”) dated August 16, 2017 with Riverstone VI Alta Mesa Holdings, L.P., a Delaware limited partnership (the “Riverstone Contributor”). The AM Contribution Agreement, the KFM Contribution Agreement and the Riverstone Contribution Agreement are together referred to as the “Contribution Agreements”. The AM Contributor, the KFM Contributor and the Riverstone Contributor are together referred to as the “Contributors”.

Pursuant to the Contribution Agreements, SRII Opco acquired (a) (i) all of the limited partner interests in Alta Mesa and (ii)100% of the economic interests and 90% of the voting interests in Alta Mesa GP, ((i) and (ii) collectively, the “AM

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Contribution") and (b) 100% of the economic interests in KFM (the "KFM Contribution"). The acquisition of Alta Mesa and KFM pursuant to the Contribution Agreements is referred to herein as the "Business Combination". SRII Opco GP, LLC, a Delaware limited liability company ("SRII Opco GP"), the sole general partner of SRII Opco, is a wholly owned subsidiary of AMR. As a result of the Business Combination, our only significant asset was our ownership at that time of an approximate 44.2% partnership interest in SRII Opco. SRII Opco owns all of the economic interests in each of Alta Mesa and KFM. SRII Opco was deemed to be a variable interest entity ("VIE") and we were deemed to be the primary beneficiary of SRII Opco and have control of SRII Opco through our voting control of SRII Opco GP.Accordingly, we consolidate both SRII Opco and SRII Opco GP, including their consolidated subsidiaries, in our financial results.

Immediately prior to the Business Combination, Alta Mesa distributed its non-STACK oil and gas assets and related liabilities to the AM Contributor.

At the closing of the Business Combination:

- we issued (i) 40,000,000 shares of our Class A Common Stock and (ii) warrants to purchase 13,333,333 shares of our Class A Common Stock to Riverstone VI SR II Holdings, L.P. ("Fund VI Holdings") pursuant to the terms of that certain Forward Purchase Agreement, dated as of March 17, 2017 (the "Forward Purchase Agreement") for cash proceeds of $400 million to us;
- we contributed $1,338 million in cash representing (i) the proceeds from the Forward Purchase Agreement and (ii) the net proceeds, after redemptions and payment of deferred underwriting compensation, of the Trust Account, less transaction fees, amounts due our Sponsor and reimbursement of seller transaction fees and costs to SRII Opco, in exchange for (i) 169,371,730 of the common units (approximately 44.2%) representing limited partner interests in SRII Opco (the "SRII Opco Common Units") and (ii) 62,966,651 warrants to purchase SRII Opco Common Units ("SRII Opco Warrants");
- we caused SRII Opco to issue 213,402,398 SRII Opco Common Units (approximately 55.8%) to the Contributors in exchange for the ownership interests in Alta Mesa, Alta Mesa GP and KFM;
- we agreed to cause SRII Opco to issue up to 59,871,031 SRII Opco Common Units to the AM Contributor and the KFM Contributor if the earn-out conditions were met pursuant to the terms of the Contribution Agreements;
- the Company issued to each of the Contributors a number of shares of Class C common stock, par value $0.0001 per share (the "Class C Common Stock"), equal to the number of the SRII Opco Common Units received by each such Contributor;
- SRII Opco distributed $814.8 million to the KFM Contributor in partial payment for the ownership interests in KFM; and
- SRII Opco entered into an amended and restated voting agreement with the owners of the remaining 10% voting interests in Alta Mesa GP whereby such other owners agreed to vote their interests in Alta Mesa GP as directed by SRII Opco.

Holders of our Class C Common Stock, together with holders of Class A Common Stock, voting as a single class, have the right to vote on all matters properly submitted to a vote of the stockholders, but holders of Class C Common Stock are not entitled to any dividends or liquidating distributions from us. The Contributors generally have the right to cause SRII Opco to redeem all or a portion of their SRII Opco Common Units in exchange for shares of our Class A Common Stock or, at SRII Opco's option, an equivalent amount of cash. However, we may, at our option, effect a direct exchange of cash or Class A Common Stock for such SRII Opco Common Units in lieu of such a redemption by SRII Opco. Upon the future redemption or exchange of SRII Opco Common Units held by a Contributor, a corresponding number of shares of Class C Common Stock will be canceled.

During 2018, the Contributors redeemed 12,341,076 of SRII Opco Common Units for an equal number of shares of Class A Common Stock through a direct exchange, whereby the 12,341,076 SRII Opco Common Units are now owned by us, and we issued an equal number of shares of our Class A Common Stock to them and canceled the related shares of our Class C Common Stock.Additionally, we sold 3,101,510 of our Common Units in SRII Opco to SRII Opco to fund purchases of an equivalent number of our Class A common shares.As a result of these and other transactions, at December 31, 2018, we now own approximately 47.0% of the limited partner interests in SRII Opco.

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Pursuant to the Contribution Agreements, for a period ofseven years following the closing, the AM Contributor and the KFM Contributor may be entitled to receive additional SRII Opco Common Units as earn-out consideration if the 20-day volume-weighted average price ("20-Day VWAP") of our Class A Common Stock equals or exceeds the following prices (each such payment, an "Earn-Out Payment"):

20-Day VWAP	Earn-Out Consideration Payable to AM Contributor	Earn-Out Consideration Payable to KFM Contributor
$14.00	10,714,285 SRII Opco Common Units	7,142,857 SRII Opco Common Units
$16.00	9,375,000 SRII Opco Common Units	6,250,000 SRII Opco Common Units
$18.00	13,888,889 SRII Opco Common Units	—
$20.00	12,500,000 SRII Opco Common Units	—

The AM Contributor and the KFM Contributor will be entitled to the earn-out consideration described above in connection with certain liquidity events of the Company, including a merger or sale of all or substantially all of our assets, if the consideration paid to holders of Class A Common Stock exceeds the above-specified 20-Day VWAP hurdles.

We also contributed $560.0 million in cash to Alta Mesa at the closing of the Business Combination.

Pursuant to final closing statements during the second quarter of 2018, the AM Contributor received an additional1,197,934 SRII Opco Common Units and an equivalent number of shares of our Class C Common Stock and the KFM Contributor remitted back to the Company$5.0 million in cash and 89,680 SRII Opco Common Units and an equivalent number of shares of our Class C Common Stock.

Purchase Price for Alta Mesa

(in thousands)?	February 9, 2018 (As initially reported)		Measurement Period Adjustment [1]		February 9, 2018 (Final)	
Purchase Consideration: [2]						
SRII Opco Common Units issued [3]	$	1,251,782	$	9,467	$	1,261,249
Estimated fair value of contingent earn-out purchase consideration [4]		284,109		—		284,109
Settlement of preexisting working capital [5]		5,476		—		5,476
Total purchase price consideration	$	1,541,367	$	9,467	$	1,550,834

(1) The measurement period adjustment relates to the issuance of1,197,934 of additional SRII Opco Common Units, valued at approximately $7.90 per unit, pursuant to a final closing statement.
(2) The purchase price consideration was for 100% of the limited partner interests in Alta Mesa and 100% of the economic interests and 90% of the voting interests in Alta Mesa GP.
(3) At closing, the Riverstone Contributor received 20,000,000 SRII Opco Common Units and the AM Contributor received 138,402,398 SRII Opco Common Units. The estimated fair value of an SRII Opco Common Unit was approximately$7.90 per unit and reflects discounts for holding requirements and liquidity.
(4) For a period of seven years following Closing, the AM Contributor will be entitled to receive earn-out consideration in the form of SRII Opco Common Units. We have determined that the fair value of the earn-out consideration was approximately$284.1 million, which was classified as equity. The fair value of the contingent earn-out was determined using the Monte Carlo simulation valuation method based on Level 3 inputs as defined in the fair value hierarchy. The key inputs included the listed market price for Class A Common Stock, market volatility of a peer group of companies similar to the Company (due to the lack of trading activity in the Class A Common Stock), no dividend yield, an expected life of each earn-out threshold based on the remaining term of the earn-out period and a risk-free rate based on U.S. dollar overnight indexed swaps with a maturity equivalent to the earn-out's expected life.
(5) Settlement of preexisting working capital balances between Alta Mesa and KFM.

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Purchase Price Allocation for Alta Mesa

(in thousands)?	February 9, 2018 (As initially reported)	Measurement Period Adjustment (1)	February 9, 2018 (Final)
Estimated Fair Value of Assets Acquired (2)			
Cash, cash equivalents and restricted cash	$ 10,345	$ —	$ 10,345
Accounts receivable	101,745	—	101,745
Other receivables	1,222	840	2,062
Receivables due from related party	907	—	907
Prepaid expenses and other	1,405	—	1,405
Derivatives	352	—	352
Property and equipment: (3)			
Oil and gas properties, successful efforts	2,314,858	(4,879)	2,309,979
Other property and equipment, net	43,318	—	43,318
Notes receivable due from related party	12,454	—	12,454
Deposits and other long-term assets	10,286	—	10,286
Total fair value of assets acquired	2,496,892	(4,039)	2,492,853
Estimated Fair Value of Liabilities Assumed (2)			
Accounts payable and accrued liabilities	210,867	(13,506)	197,361
Advances from non-operators	6,803	—	6,803
Advances from related party	47,506	—	47,506
Asset retirement obligations (3)	5,998	—	5,998
Derivatives	11,585	—	11,585
Long-term debt (4)	667,700	—	667,700
Other long-term liabilities	5,066	—	5,066
Total fair value of liabilities assumed	955,525	(13,506)	942,019
Total consideration and fair value	$ 1,541,367	$ 9,467	$ 1,550,834

(1) The measurement period adjustments were recognized in the reporting period in which the adjustments were determined. The measurement period adjustments relate to a change in the purchase consideration based on the final closing statement and certain adjustments to beginning balances.
(2) The assets acquired and liabilities assumed relate to Alta Mesa's STACK assets.
(3) The estimated fair value of oil and gas properties and asset retirement obligations were determined using valuation techniques that convert future cash flows to a single discounted amount and involve the use of certain inputs that are not observable in the market (Level 3 inputs). Significant inputs include, but are not limited to recoverable reserves, production rates, future operating and development costs, future commodity prices, appropriate risk-adjusted discount rates and other relevant data. These inputs required significant judgments and estimates by management at the time of the valuation. Actual results may vary from these estimates.
(4) Represents the approximate fair value as of the acquisition date of (i) $533.6 million associated with Alta Mesa's 2024 Notes with a $500.0 million aggregate principal amount based on Level 1 inputs, and (ii) $134.1 million of outstanding borrowings under the Alta Mesa Predecessor Credit Facility.

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Purchase Price for KFM

(in thousands)?	February 9, 2018 (As initially reported)	Measurement Period Adjustments (1)	February 9, 2018 (Final)
Purchase Consideration:			
Cash (2)	$ 814,820	$ (5,008)	$ 809,812
SRII Opco Common Units issued (3)	434,640	(709)	433,931
Estimated fair value of contingent earn-out purchase consideration (4)	88,105	—	88,105
Settlement of preexisting working capital (5)	(5,476)	—	(5,476)
Total purchase price consideration	$ 1,332,089	$ (5,717)	$ 1,326,372

(1) The measurement period adjustments pursuant to a final closing statement.
(2) The cash consideration paid at February 9, 2018 was net of estimated net working capital adjustments, transaction expenses, capital expenditures and banking fees.
(3) At closing, the KFM Contributor received 55,000,000 SRII Opco Common Units valued at approximately $7.90 per unit, reflecting discounts for holding requirements and liquidity.
(4) The KFM earn-out consideration was recognized at fair value and has been classified in stockholders' equity. The fair value of the earn-out was determined using the Monte Carlo simulation valuation method based on Level 3 inputs. The key inputs included the quoted market price for the Company's Class A Common Stock, market volatility of a peer group of companies similar to the Company (due to the lack of trading activity in the Company's Class A Common Stock), no dividend yield, an expected life of each earn-out threshold based on the remaining term of the earn-out period and a risk-free rate based on U.S. dollar overnight indexed swaps.
(5) Settlement of preexisting working capital between Alta Mesa and KFM.

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Purchase Price Allocation for KFM

(in thousands)?	February 9, 2018 (As initially reported)	Measurement Period Adjustments [1]	February 9, 2018 (Final)
Estimated Fair Value of Assets Acquired			
Cash and cash equivalents	$ 7,648	$ —	$ 7,648
Accounts receivable	4,334	—	4,334
Prepaid expenses	550	—	550
Property, plant and equipment: [2]			
Pipeline	272,442	11,272	283,714
Other property, plant and equipment	519	(14)	505
Intangible assets [3]	472,432	(58,282)	414,150
Goodwill [4]	650,663	41,307	691,970
Total fair value of assets acquired	1,408,588	(5,717)	1,402,871
Estimated Fair Value of Liabilities Assumed			
Accounts payable and accrued liabilities	33,499	—	33,499
Long-term debt	43,000	—	43,000
Total fair value of liabilities assumed	76,499	—	76,499
Total consideration and fair value	$ 1,332,089	$ (5,717)	$ 1,326,372

(1) The measurement period adjustments relate to the final closing statement, a revision in the value of KFM's customer relationship intangible assets resulting from an adjustment to the initial discount rate used and certain adjustments to beginning balances.
(2) The estimated fair value was determined using valuation techniques that convert future cash flows to a single discounted amount and involved the use of certain inputs that are not observable in the market (Level 3 inputs). These valuations required significant judgments and estimates by management at the time of the valuation. Actual results may vary from these estimates.
(3) Intangible assets acquired were primarily related to customer relationships held by KFM prior to Closing, recorded at estimated fair value determined using the income approach and involve the use of certain inputs that are not observable in the market (Level 3 inputs).These valuations required significant judgments and estimates by management at the time of the valuation.
(4) Goodwill represented the excess of the consideration paid above the fair value of identified assets acquired and liabilities assumed and principally related to the expected synergies with the relationship to Alta Mesa.

Unaudited Pro Forma Operating Results

The following unaudited pro forma combined financial information has been prepared as if the Business Combination and other related transactions had taken place on January 1, 2017.

The information reflects pro forma adjustments based on available information and certain assumptions that we believe are reasonable. Pro forma earnings for the 2018 Predecessor Period and the year ended December 31, 2017, were adjusted to exclude$65.2 million of transaction-related costs incurred by the Company, Alta Mesa and KFM. These costs are not included as they are directly related to the Business Combination and are nonrecurring.

The pro forma combined financial information has been included for comparative purposes and is not necessarily indicative of the results that might have occurred had the Business Combination taken place on January 1, 2017. The financial information is not intended to be a projection of future results.

(in thousands)?	January 1, 2018 Through February 8, 2018	Year Ended December 31, 2017
Total operating revenue	$ 49,500	$ 361,072
Net income (loss)	3,465	(50,372)
Net income (loss) attributable to Alta Mesa Resources, Inc. stockholders	1,304	(16,454)
Basic net income (loss) per share	0.01	(0.10)
Diluted net income (loss) per share	0.01	(0.10)

Acquisition of acreage

In October 2018, we completed a transaction to acquire certain unproved oil and gas properties for$22.3 million, net of customary post-closing purchase price adjustments. The acquisition was funded utilizing borrowings under the Alta Mesa RBL.

2017 Activity

In December 2017, Alta Mesa sold its assets located in the Weeks Island field to Texas Petroleum Investment for$22.5 million.

In September 2017, Alta Mesa acquired certain proved oil and gas properties for$8.2 million, using cash on hand. We determined the fair value of the net assets acquired was approximately $9.9 million. Accordingly, a bargain purchase gain of $1.7 million was recognized at the time of the acquisition. The gain primarily resulted from growth in reserves and value between signing and closing of the transaction.

In July 2017, Alta Mesa acquired oil and gas properties in Oklahoma for$45.6 million, funded with borrowings under Alta Mesa's Predecessor credit facility.

2016 Activity

During 2016, Alta Mesa acquired approximately $10.6 million of oil and gas properties in Oklahoma which were primarily related to unevaluated leasehold.

On December 31, 2016, Alta Mesa's Class B limited partner, High Mesa, Inc. ("HMI") purchased from BCE-STACK Development LLC ("BCE") and contributed interests in 24 producing wells (the "Contributed Wells") to Alta Mesa. Alta Mesa recorded HMI's equity contribution at the fair value of the wells contributed of approximately $65.7 million, plus contributed cash of $11.3 million, of which $7.9 million was collected subsequent to December 31, 2016.

NOTE 9 — PROPERTY, PLANT AND EQUIPMENT

(in thousands)?	Successor December 31, 2018	Predecessor December 31, 2017
Oil and gas properties		
Unproved properties	$ 816,282	$ 84,590
Accumulated impairment of unproved properties	(742,065)	—
Unproved properties, net	74,217	84,590
Proved oil and gas properties	2,110,346	1,061,105
Accumulated depreciation, depletion, amortization and impairment	(1,421,226)	(251,065)
Proved oil and gas properties, net	689,120	810,040
Total oil and gas properties, net	763,337	894,630
Other property, plant and equipment		
Land	5,059	2,912
Fresh water wells	27,366	—
Produced water disposal system	104,498	30,990
Gas processing plant and gathering lines	380,470	—
Office furniture, equipment and vehicles	4,244	20,008
Accumulated depreciation and impairment	(77,368)	(21,770)
Other property, plant and equipment, net	444,269	32,140
Total property, plant and equipment, net	$ 1,207,606	$ 926,770

Depreciation and Depletion

(in thousands)	Successor February 9, 2018 Through December 31, 2018	Predecessor January 1, 2018 Through February 8, 2018	Predecessor Year Ended December 31, 2017	Predecessor Year Ended December 31, 2016
Oil and gas properties depletion	$ 129,579	$ 11,021	$ 83,537	$ 49,481
Midstream tangible asset depreciation	8,235	—	—	—
Other property, plant and equipment depreciation	3,236	609	5,240	4,004
Total depletion and depreciation	$ 141,050	$ 11,630	$ 88,777	$ 53,485

Sale of Produced Water Assets

In November 2018, Alta Mesa sold its produced water assets, consisting of over 200 miles of produced water gathering pipelines and20 disposal wells, surface leases, easements and other agreements, to a subsidiary of KFM for approximately$99 million, including approximately $90 million in cash at closing and $9 million of purchase price adjustments which, in total, approximated the net book value of the produced water assets. This transaction was accounted for as a transfer of assets among entities under common control and recorded at carrying value.Accordingly, no gain or loss was recognized. In conjunction with the sale, Alta Mesa entered into a new fifteen-year produced water disposal agreement with KFM.

NOTE 10 — DISCONTINUED OPERATIONS (Predecessor)

Alta Mesa distributed its remaining non-STACK oil and gas assets and liabilities to the AM Contributor just prior to the closing of the Business Combination. We have determined that these non-STACK oil and gas assets and liabilities, as well as the Weeks Island field sold during the 4th quarter of 2017, are discontinued operations during the Predecessor Periods and we have segregated their financial information from ours in the financial statements.

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Prior to the Business Combination, Alta Mesa had notes payable to its founder ("Founder Notes") that bore simple interest at10%. The Founder Notes were part of the non-STACK distribution. The balance of the Founder Notes at the time of conversion was approximately$28.3 million, including accrued interest. Interest on the Founder Notes was$0.1 million, $1.2 million and $1.2 million for the 2018 Predecessor Period and the years ended December 31, 2017 and 2016, respectively.

?		Predecessor
(in thousands)?		**December 31, 2017**
Assets associated with discontinued operations:		
Current assets		
Cash	$	61
Accounts receivable		4,980
Other receivables		154
Total current assets		5,195
Noncurrent assets		
Investments		9,000
Oil and gas properties, net		33,618
Other long-term assets		1,167
Total noncurrent assets		43,785
Total assets associated with discontinued operations	$	48,980
?		
Liabilities associated with discontinued operations:		
Current liabilities		
Accounts payable and accrued liabilities	$	7,882
Asset retirement obligations		7,537
Total current liabilities		15,419
Noncurrent liabilities		
Asset retirement obligations, net of current portion		37,049
Founder notes		28,166
Other long-term liabilities		1,647
Total noncurrent liabilities		66,862
Total liabilities associated with discontinued operations	$	82,281

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? (in thousands)?	January 1, 2018 Through February 8, 2018	Year Ended December 31, 2017	Year Ended December 31, 2016
Revenue:			
Oil	$ 1,617	$ 47,218	$ 57,866
Natural gas	1,023	10,090	10,932
Natural gas liquids	236	2,359	1,489
Other	16	316	213
Operating revenue	2,892	59,983	70,500
Gain (loss) on sale of assets	(1,923)	(22,207)	3,539
Gain on acquisition of oil and gas properties	—	1,626	—
Total revenue	969	39,402	74,039
Operating expenses:			
Lease operating	1,770	27,763	29,474
Transportation and marketing	83	1,354	1,698
Production taxes	167	6,730	7,985
Workover	127	2,088	1,273
Exploration	—	11,431	7,547
Depreciation, depletion and amortization	884	24,519	41,320
Impairments of assets	5,560	29,129	15,924
General and administrative	21	82	1,290
Total operating expenses	8,612	103,096	106,511
Other income (expense)			
Interest expense	(103)	(1,209)	(1,209)
Interest income and other	—	88	10
Total other expense	(103)	(1,121)	(1,199)
Income tax provision (benefit)	—	—	(29)
Loss from discontinued operations, net of state income taxes	$ (7,746)	$ (64,815)	$ (33,642)

?	Predecessor		
(in thousands)?	January 1, 2018 Through February 8, 2018	Year Ended December 31, 2017	Year Ended December 31, 2016
Total operating cash flows of discontinued operations	$ 2,974	$ 21,138	$ 31,255
Total investing cash flows of discontinued operations	(601)	6,891	(14,378)

NOTE 11 — FAIR VALUE MEASUREMENTS

Recurring measurements

We utilize the modified Black-Scholes and the Turnbull Wakeman option pricing models to estimate the fair values of oil and gas derivatives. Inputs to these models include observable inputs from the NYMEX for futures contracts, and inputs derived from NYMEX observable inputs, such as implied volatility of oil and gas prices. We have classified the inputs used to determine fair values of all our oil, gas and natural gas liquids derivative contracts as Level 2.

Non-recurring measurements

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In connection with the Business Combination, we recorded the fair value of Alta Mesa's 2024 Notes at$533.6 million. We estimated the fair value of the senior notes to be $312.5 million at December 31, 2018, based on the most recent trading values of the senior notes at or near the reporting date, which is a Level 1 determination.

Oil, gas, and midstream properties, as well as our goodwill and intangible assets in our Midstream segment are subject to impairment testing and potential impairment based largely on future estimated cash flows determined using Level 3 inputs.

	Successor			Predecessor		
	December 31, 2018			December 31, 2017		
(in thousands)	Original Carrying Value (1)	Estimated Fair Value	Impairment	Original Carrying Value (1)	Estimated Fair Value	Impairment
Unproved oil and gas properties	$ 816,282	$ 74,217	$ 742,065	$ —	$ —	$ —
Proved oil and gas properties	1,895,670	604,023	1,291,647	3,350	2,162	1,188
Equity method investment	17,063	1,100	15,963	—	—	—
Midstream property, plant and equipment	474,529	406,122	68,407	—	—	—
Intangible assets	394,999	—	394,999	—	—	—
Goodwill	691,970	—	691,970	—	—	—
Total	$ 4,290,513	$ 1,085,462	$ 3,205,051	$ 3,350	$ 2,162	$ 1,188

(1) Associated with impaired assets.

We estimate the fair value of additions to asset retirement obligations associated with new or acquired properties. Such estimations of fair value are based on present value techniques that utilize company-specific information for inputs such as the cost and timing of plugging and abandonment of wells and facilities. These inputs are classified as Level 3.

NOTE 12 — DERIVATIVES

Substantially all of our derivatives are executed by lenders under the Alta Mesa RBL, and are collateralized by the security interests thereunder. The derivatives settle monthly. No derivatives have been entered into for trading or speculative purposes and none have been designated as hedges under GAAP.

From time to time, we may enter into interest rate swap agreements to mitigate the risk of changes in interest rates, but as of December 31, 2018, we have none.

The following summarizes the fair value and classification of our derivatives:

?	December 31, 2018 (Successor)		
Balance sheet location	Gross fair value of assets	Gross liabilities offset against assets in the Balance Sheet	Net fair value of assets presented in the Balance Sheet
?		(in thousands)	
Derivatives, current assets	$ 22,512	$ (6,089)	$ 16,423
Derivatives, long-term assets	7,910	(4,963)	2,947
Total	$ 30,422	$ (11,052)	$ 19,370

Balance sheet location	Gross fair value of liabilities	Gross assets offset against liabilities in the Balance Sheet	Net fair value of liabilities presented in the Balance Sheet
?		(in thousands)	
Derivatives, current liabilities	$ 7,799	$ (6,089)	$ 1,710
Derivatives, long-term liabilities	5,143	(4,963)	180
Total	$ 12,942	$ (11,052)	$ 1,890

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Balance sheet location	Gross fair value of assets	Gross liabilities offset against assets in the Balance Sheet	Net fair value of assets presented in the Balance Sheet
	December 31, 2017 (Predecessor)		
?		(in thousands)	
Derivatives, current assets	$ 1,406	$ (1,190)	$ 216
Derivatives, long-term assets	3,010	(3,002)	8
Total	$ 4,416	$ (4,192)	$ 224

Balance sheet location	Gross fair value of liabilities	Gross assets offset against liabilities in the Balance Sheet	Net fair value of liabilities presented in the Balance Sheet
?		(in thousands)	
Derivatives, current liabilities	$ 20,493	$ (1,190)	$ 19,303
Derivatives, long-term liabilities	4,116	(3,002)	1,114
Total	$ 24,609	$ (4,192)	$ 20,417

The following table summarizes the effect of our derivatives in the statements of operations (in thousands):

?	Successor	Predecessor		
Derivatives not designated as hedges	February 9, 2018 Through December 31, 2018	January 1, 2018 Through February 8, 2018	Year Ended December 31, 2017	Year Ended December 31, 2016
Gain (loss) on derivatives -				
Oil commodity contracts	$ (3,559)	$ 4,796	$ 1,450	$ (36,572)
Natural gas commodity contracts	(6,688)	1,867	7,288	(2,410)
Natural gas liquids commodity contracts	—	—	(451)	(1,478)
Total gain (loss) on derivatives	$ (10,247)	$ 6,663	$ 8,287	$ (40,460)

Other receivables at December 31, 2018 and 2017 include $1.3 million and $1.4 million, respectively, of derivative positions covering the month of December to be settled in January of the succeeding year.

We periodically monitor the creditworthiness of our counterparties. Although our counterparties provide no collateral, the agreements with each counterparty allow us to set-off unpaid amounts against the outstanding balance under the Alta Mesa RBL.

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We had the following call and put derivatives at December 31, 2018:

OIL

? Settlement Period and Type of Contract	Volume in bbls	Weighted Average	Range High	Range Low
2019				
Price Swap Contracts	182,500	$ 63.03	$ 63.03	$ 63.03
Collar Contracts				
Short Call Options	2,701,000	66.31	75.20	56.50
Long Put Options	2,883,500	53.80	62.00	50.00
Short Put Options	2,883,500	42.72	52.00	37.50
2020				
Collar Contracts				
Short Call Options	585,600	64.32	73.80	59.55
Long Put Options	1,537,200	55.54	62.50	50.00
Short Put Options	1,537,200	44.64	50.00	37.50

NATURAL GAS

? Settlement Period and Type of Contract	Volume in MMBtu	Weighted Average	Range High	Range Low
2019				
Price Swap Contracts	10,905,000	$ 2.69	$ 3.09	$ 2.64
Collar Contracts				
Short Call Options	4,000,000	3.31	3.75	3.17
Long Put Options	3,550,000	2.81	2.90	2.70
Short Put Options	2,425,000	2.27	2.40	2.20
2020				
Collar Contracts				
Short Call Options	2,275,000	3.19	3.20	3.17
Long Put Options	9,150,000	2.57	2.70	2.50
Short Put Options	9,150,000	2.07	2.20	2.00
2021				
Collar Contracts				
Long Put Options	2,250,000	2.65	2.65	2.65
Short Put Options	2,250,000	2.15	2.15	2.15

In those instances where contracts are identical as to time period, counterparty, volume and strike price, but opposite as to direction (long and short), the volumes and average prices have been netted in the two tables above. Prices stated in the table above for oil may settle against either the NYMEX index or may reflect a mix of positions settling on various combinations of these benchmarks.

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We had the following basis swaps at December 31, 2018:

Total Gas Volumes in MMBtu over Remaining Term(1)	Reference Price 1 (1)	Reference Price 2 (1)	Period			Weighted Average Spread ($ per MMBtu)	
460,000	OneOK	NYMEX Henry Hub	Jul '19	—	Dec '19	$	(0.93)
17,950,000	Tex/OKL Panhandle Eastern Pipeline	NYMEX Henry Hub	Jan '19	—	Dec '19		(0.68)
910,000	Tex/OKL Panhandle Eastern Pipeline	NYMEX Henry Hub	Jan '20	—	Mar '20		(0.49)
2,365,000	San Juan	NYMEX Henry Hub	Jan '19	—	Oct '19		(0.78)

(1) Represents short swaps that fix the basis differentials between OneOK, Tex/OKL Panhandle Eastern Pipeline ("PEPL"), San Juan and NYMEX Henry Hub.

NOTE 13 — INTANGIBLE ASSETS

Our intangible assets represent customer relationships within the Midstream segment acquired in the Business Combination.

	Successor	
(in thousands)?	**December 31, 2018**	
Customer contracts and relationships	$	414,150
Accumulated amortization and impairment		(414,150)
Intangibles, net	$	—

Amortization expense was $19.2 million during the Successor Period.

NOTE 14 — EQUITY METHOD INVESTMENT

In May 2018, a subsidiary of KFM entered into agreements with a third party to jointly construct and operate a new crude oil pipeline via creation of Cimarron that we accounted for under the equity method. Cimarron's proposed pipeline was to extend from our processing plant to Cushing, Oklahoma and was to be constructed and operated by Cimarron, which we determined was controlled by the non-KFM owner.Through December 31, 2018, we had invested $17.1 million in Cimarron, but we also impaired this investment to reduce its carrying value to our portion of the estimated cash remaining after satisfaction of liabilities.

	In thousands	
Balance, as of February 9, 2018	$	—
Capital contributions		17,063
Impairment		(15,963)
Balance, as of December 31, 2018	$	1,100

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NOTE 15 — ASSET RETIREMENT OBLIGATIONS

(in thousands)?	2018	Predecessor 2017
Balance, as of January 1 (Predecessor)	$ 10,469	$ 8,400
Liabilities settled	(63)	
Revisions to estimates	63	
Accretion expense	39	
Balance, as of February 8 (Predecessor)	$ 10,508	
?		
Fair value per Business Combination, as of February 9 (Successor)(1)	$ 5,998	
Liabilities assumed	—	604
Liabilities incurred	2,676	1,583
Liabilities settled	(1,610)	(119)
Liabilities transferred via sale	(19)	—
Revisions to estimates	3,766	(337)
Accretion expense	741	338
Balance, as of December 31	11,552	10,469
Less: Current portion	2,079	69
Long-term portion	$ 9,473	$ 10,400

(1) Represents the same wells under the Predecessor Period but valued at a higher interest rate of10.2% compared to Predecessor interest rates ranging between 4.4% and 8.8%.

NOTE 16 — LONG-TERM DEBT, NET

?	Successor	Predecessor
(in thousands)?	December 31, 2018	December 31, 2017
Alta Mesa RBL	$ 161,000	$ —
Alta Mesa Predecessor Credit Facility	—	117,065
KFM Credit Facility	174,000	—
2024 Notes	500,000	500,000
Unamortized premium on 2024 notes	29,123	—
Unamortized deferred financing costs	—	(9,625)
Total debt, net	864,123	607,440
Less: Current portion	690,123	—
Long-term debt, net	$ 174,000	$ 607,440

Alta Mesa RBL

In connection with the Business Combination, we entered into the Alta Mesa RBL which has a face amount of$1.0 billion and had an initial $350.0 million borrowing base. In April 2018, the borrowing base was increased to $400.0 million, which was reaffirmed by the lenders during the fourth quarter of 2018. Drawing on the Alta Mesa RBL requires us to be in compliance with the covenants on a current and pro forma basis.As of December 31, 2018, in addition to $161.0 million of borrowings outstanding, we also had $21.9 million of outstanding letters of credit, leaving a total borrowing capacity of $217.1 million available for future use at that time. On April 1, 2019, the borrowing base was reduced to$370.0 million upon completion of the regularly scheduled semiannual redetermination. In August 2019, the lenders exercised their option to conduct an optional redetermination, pursuant to which they established a revised borrowing base of $200.0 million, which will require us to make monthly installments of $32.5 million for five months beginning in September 2019. As a consequence of reduced operating cash flow and a lowered borrowing base, we have limited ability to obtain the capital necessary to conduct our operations at desired levels. Additionally, if we are in default under the Alta Mesa RBL, the lenders could cease making amounts available,

accelerate payment of amounts outstanding or seek other remedies any of which would further limit our access to the capital necessary to fund our capital expenditures.

The facility matures in February 2023 and is subject to semiannual redeterminations. In addition, each of the lender group and us has the right to request one additional redetermination of the borrowing base between scheduled redeterminations. We may borrow in Eurodollars or at a reference rate. Eurodollar loans bear interest at a rate per annum equal to the applicable LIBOR rate, plus a margin ranging from2.00% to 3.00%. Reference rate loans bear interest at a rate per annum equal to the greater of (i) the agent bank's prime rate, (ii) the federal funds effective rate plus50 basis points or (iii) the rate for one-month Eurodollar loans plus1.00%, plus a margin ranging from 1.00% to 2.00%.

The amounts outstanding are secured by first priority liens on substantially all of our upstream oil and gas properties and all of the equity of our material guarantor subsidiaries. Additionally, SRII Opco and Alta Mesa GP have pledged their respective partner interests as security.

Restrictive covenants may limit our ability to incur additional indebtedness, sell assets, guarantee or make loans to others, make investments, enter into mergers, make certain payments and distributions in excess of specific amounts, enter into or be party to hedge agreements, amend organizational documents, incur liens and engage in certain other transactions without the prior consent of the lenders.

The Alta Mesa RBL has two maintenance covenants that are tested quarterly according to the definitions and provisions thereunder:

- a ratio of our current assets to current liabilities, inclusive of specified adjustments, of not less than1.0 to 1.0; and
- a ratio of our consolidated debt to our consolidated EBITDAX of not greater than4.0 to 1.0. Through December 31, 2018 we were able to annualize cumulative Successor Period results in measuring EBITDAX.

Predecessor Credit Facility

As of December 31, 2017, Alta Mesa had $117.1 million of borrowings outstanding, which were paid in full at the time of the Business Combination.

KFM Credit Facility

Prior to May 30, 2018, KFM had a revolving credit facility that it had entered into in August 2017. The borrowings outstanding under this facility at May 30, 2018 totaled $59.5 million.

Effective May 30, 2018, KFM entered into the KFM Credit Facility with an aggregate committed amount of$300.0 million, which replaced the prior credit facility. The KFM Credit Facility matures on May 30, 2023. Initial borrowings of $62.5 million under this new facility were utilized to extinguish the prior credit facility, including accrued interest and related fees and expenses. As of December 31, 2018, there were no outstanding letters of credit and remaining borrowing capacity of $126.0 million.

Notwithstanding the below information regarding the April 2019 amendment and waiver, availability under the KFM Credit Facility is determined as the lesser of (1) the $300.0 million of aggregate commitments and (2) the maximum amount that, together with the aggregate amount of all then-outstanding consolidated funded indebtedness (other than indebtedness under the KFM Credit Facility) would result in KFM being in pro forma compliance with all applicable leverage ratios at such time. As of December 31, 2018, KFM has no debt other than the KFM Credit Facility and therefore, the $300.0 million remains the availability amount.

The amounts outstanding under the KFM Credit Facility are secured by first priority liens on substantially all of KFM's assets. Additionally, SRII Opco, LP has pledged its membership interests in KFM as collateral.

We may borrow under the KFM Credit Facility in Eurodollars or at a reference rate, with such borrowings bearing interest, payable quarterly for reference rate loans or, for Eurodollar loans, on the last day of the applicable interest period. Eurodollar loans bear interest at a rate per annum equal to the applicable LIBOR rate, plus a margin ranging from 2.00% to 3.25%. Reference rate loans bear interest at a rate per annum equal to the greater of (i) the agent bank's prime rate, (ii) the federal funds

effective rate plus 50 basis points or (iii) the rate for one-month Eurodollar loans plus1.00%, plus an applicable margin ranging from 1.00% to 2.25%.

Restrictive covenants limit our ability to incur additional indebtedness, dispose of assets, make loans to others, make investments, enter into mergers, make certain payments and distributions, enter into or be party to hedge agreements, amend organizational documents, incur liens and engage in certain other transactions.

The KFM Credit Facility has two maintenance covenants that are tested quarterly:

- a ratio of our total debt to consolidated adjusted EBITDA of not greater than4.5 to 1.0 (which increases to 4.75 after we exceed consolidated EBITDA of $75.0 million) for any 4 quarter period; and
- a minimum interest coverage ratio of our adjusted EBITDA to interest expense of not less than2.5 to 1.0.

In addition, if KFM makes an election to increase the Total Leverage Ratio in order to issue unsecured debt, it would be required to maintain a ratio of senior unsecured debt to adjusted EBITDA of greater than 3.5 to 1.0.

Amendment and Waiver to the KFM Credit Facility

KFM failed to timely provide its lenders quarterly financial statements for the quarter ended December 31, 2018, and failed to provide the lenders notice in connection with its acquisition of the produced water assets from Alta Mesa, including the delivery of certain recorded instruments of transfer. In April 2019, KFM entered into an amendment and limited waiver (the "Amendment") to the KFM Credit Facility to waive the defaults and events of default arising or resulting from those failures. The Amendment also extended the deadline for delivery of audited financial statements for 2018 and the deadline for the unaudited financial statements for the quarter ended March 31, 2019, which KFM subsequently met. Further, the Amendment adds provisions which limit the maximum amount of cash KFM can hold to $15.0 million. The Amendment also generally provides that any amendment to a material contract with an affiliate during a six-month period that causes a reduction to projected total revenue by more than 15% constitutes an event of default.

2024 Notes

Our 2024 Notes have a face value of $500.0 million and bear interest at 7.875% per annum. The 2024 Notes were issued at par during the 4th quarter of 2016 in a private placement but were exchanged for substantially identical registered senior notes in November 2017. The midstream assets held by KFM provide no collateral to the 2024 Notes.

The 2024 Notes mature in December 2024 with interest payable semi-annually on June 15 and December 15. Before December 2019, we may (i) redeem up to 35% of the 2024 Notes using proceeds from equity offerings at a redemption price of107.875% of principal under specified conditions, or (ii) we otherwise may redeem the 2024 Notes at their principal amount plus an applicable make-whole premium.

On and after December 15, 2019, Alta Mesa may redeem the 2024 Notes, in whole or in part, at the following redemption prices plus accrued and unpaid interest, if any, to the date of redemption:

	After December 15,			
	2019	2020	2021	2022
Redemption price as a percentage of principal amount	105.906%	103.938%	101.969%	100%

The 2024 Notes are guaranteed by each of Alta Mesa's subsidiaries and rank equal in right of payment to all of Alta Mesa's existing and future senior indebtedness; senior in right of payment to all of Alta Mesa's existing and future subordinated indebtedness; effectively subordinated to all of Alta Mesa's existing and future secured indebtedness to the extent of the value of the collateral securing such indebtedness, including amounts outstanding under the Alta Mesa RBL; and structurally subordinated to all existing and future indebtedness and obligations of any of Alta Mesa's subsidiaries that do not guarantee the 2024 Notes.

The 2024 Notes contain certain covenants limiting our ability to prepay subordinated indebtedness, pay distributions, redeem stock or make certain restricted investments; incur indebtedness; create liens on Alta Mesa's assets to secure debt; restrict dividends, distributions or other payments; enter into transactions with affiliates; designate subsidiaries as unrestricted subsidiaries; sell or otherwise transfer or dispose of assets, including equity interests of restricted subsidiaries; effect a consolidation or merger; and change Alta Mesa's line of business. The Alta Mesa RBL and the 2024 Notes have cross default

provisions, which could result in the acceleration of indebtedness under both agreements if we fail to comply with the covenants and other provisions in either agreement. Upon certain changes of control, the terms of the notes may require us to redeem them at101% of the principal amount. The Business Combination did not constitute a change in control for the 2024 Notes.If an event of default occurs, all outstanding amounts may become due and payable.

Bond Premium

The fair value of the 2024 Notes as of the Business Combination was$533.6 million yielding a bond premium of$33.6 million. Amortization of the premium reduced our interest expense by $4.5 million during the Successor Period.

Scheduled Maturities of Debt (Successor)

Fiscal Year?	(in thousands)
2019	$ —
2020	—
2021	—
2022	—
2023	335,000
Thereafter	500,000
?	$ 835,000

Based on the factors leading to the substantial unresolved doubt about our ability to continue as a going concern and the reduced borrowing base under the Alta Mesa RBL that went into effect in August 2019, we believe that it is highly likely that repayment of the debt outstanding under the Alta Mesa RBL and the 2024 Notes will accelerate prior to December 31, 2019, and earlier than the scheduled maturities shown above. Accordingly, we have reported the debt outstanding under the Alta Mesa RBL and the 2024 Notes as current as ofDecember 31, 2018.

Subsidiary Guarantors

All of Alta Mesa's wholly owned subsidiaries are guarantors under the terms of its 2024 Notes and the RBL. The guarantees are full and unconditional (except for customary release provisions) and are joint and several.KFM's wholly owned subsidiaries are guarantors under the terms of the KFM Credit Facility. Our consolidated financial statements reflect the financial position of these subsidiary guarantors.

Deferred Financing Costs

As of December 31, 2017, we had $11.4 million of deferred financing costs related to both the 2024 Notes and the Predecessor Credit Facility. Pursuant to the Business Combination, the unamortized deferred financing costs were adjusted to a fair value ofzero. During the Successor Period, we incurred additional deferred financing costs related to the Alta Mesa RBL and the KFM Credit Facility of$1.4 million and $2.3 million, respectively. For the Successor Period, the 2018 Predecessor Period, and the years endedDecember 31, 2017 and 2016, the amortization of deferred financing costs was $0.5 million, $0.2 million, $2.7 million, and $3.9 million, respectively.

NOTE 17 — ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

?	Successor	Predecessor
(in thousands)?	**December 31, 2018**	**December 31, 2017**
Accounts payable	$ 20,422	$ 68,578
Accruals for capital expenditures	139,904	48,771
Revenue and royalties payable	50,241	29,514
Accruals for operating expenses	21,830	14,632
Accrued interest	2,477	2,587
Derivative settlements	109	2,106
Other	12,456	4,301
Total accrued liabilities	227,017	101,911
Accounts payable and accrued liabilities	$ 247,439	$ 170,489

NOTE 18 — COMMITMENTS AND CONTINGENCIES

Commitments

Office and Equipment Leases

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We lease office space and certain field equipment under long-term operating lease agreements. For the Successor Period, the 2018 Predecessor Period and the years ended December 31, 2017 and 2016, total net lease payments were approximately $7.8 million, $0.1 million, $7.8 million and $3.6 million, respectively.

At December 31, 2018, we have the remaining future minimum lease payments:

Fiscal Year	In thousands
2019	$ 2,837
2020	2,870
2021	2,918
2022	3,107
2023	3,038
Thereafter	12,219
	$ 26,989

Firm Natural Gas Transportation Commitments

We have entered into certain firm commitments intended to secure capacity on third party pipelines for transportation of natural gas that extend through 2036 with the following remaining minimum commitments at December 31, 2018:

(amounts in thousands)	Upstream	Midstream(1)	Total
2019	$ 12,236	$ 6,778	$ 19,014
2020	12,236	6,116	18,352
2021	12,236	6,116	18,352
2022	12,236	5,859	18,095
2023	12,236	5,676	17,912
Thereafter	25,023	70,004	95,027
	$ 86,203	$ 100,549	$ 186,752

(1) Total cash payments required for committed capacity in MMBtus of 49,865,000 in 2019, 45,750,000 in 2020, 45,625,000 in 2021, 40,275,000 in 2022, 36,500,000 in 2023 and 450,450,000 thereafter. KFM does not currently utilize the full amount of contracted capacity but strives to release capacity to third parties to attempt to minimize the under-utilization.

Other Commitments

KFM has entered into 2 commitments with other midstream providers with the following significant terms:

An annual commitment for 3,650,000 mcf of processing volumes that runs through December 31, 2021. KFM is required to pay $0.85 per mcf for any shortfall volumes. Volumes processed under this contract are sold to the processor at market value after processing. KFM has entered into an agreement with Alta Mesa whereby Alta Mesa will reimburse KFM for half of the expenses associated with any shortfall.

A commitment for $125,000 per month of processing services that runs through December 31, 2021. Although there are no associated volumetric minimums, KFM is required to pay for the value of any shortfall from the $125,000 monthly fee. Any volumes processed under this contract are sold to the processor at prevailing market prices after processing.

KFM had also entered into a commitment to deliver 7,125 barrels of NGLs per day through May 31, 2019. KFM was required to pay $1.89 per barrel for any shortfall volumes. Volumes provided under this contract were purchased by the counterparty at prevailing market prices at the time of sale.

Contingencies

Environmental claims

Various landowners have sued Alta Mesa in lawsuits concerning several fields in which Alta Mesa's subsidiaries have, or historically had, operations. The lawsuits seek injunctive relief and other relief, including unspecified amounts in both actual and punitive damages for alleged breaches of mineral leases and alleged failure to restore the plaintiffs' lands from alleged contamination and otherwise from its oil and gas operations. We are unable to express an opinion with respect to the likelihood of an unfavorable outcome of the various environmental claims or to estimate the amount or range of potential loss should the outcome be unfavorable. Therefore, we have not provided any material amounts for these claims in our consolidated financial statements at December 31, 2018.

Title/lease disputes

Title and lease disputes may arise in the normal course of our operations. These disputes are usually small but could result in an increase or decrease in reserves and/or other forms of settlement, such as cash, once a final resolution to the title dispute is made.

Litigation

On January 30, 2019, the Company, James T. Hackett, our interim Chief Executive Officer and Chairman of the Board, certain of our former and current directors, Thomas J. Walker, our former Chief Financial Officer, and Riverstone Investment Group LLC were named as defendants in a putative securities class action filed in the United States District Court for the Southern District of New York ("SDNY Complaint").The plaintiff, Plumbers and Pipefitters National Pension Fund, alleges that the defendants disseminated a false and misleading proxy statement in connection with the Business Combination and, therefore, violated Section 14(a) of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), and Rule 14-9 promulgated thereunder. In addition, the plaintiff alleges that Riverstone and the individual defendants violated Section 20(a) of the Exchange Act. The plaintiff is seeking compensatory and/or rescissory damages against the defendants.The District Court transferred this action to the U.S. District Court for the Southern District of Texas.

On March 14 and 19, 2019, two additional putative securities class action complaints were filed in the U.S. District Court for the Southern District of Texas ("SDTX Complaints") against the same defendants named in the SDNY Complaint, and Harlan H. Chappelle and Michael A. McCabe, our former President and Chief Executive Officer and Chief Financial Officer, respectively.These complaints include the same claims asserted in the initial complaint, but also add claims under Section 10(b) of the Exchange Act and Rule 10b-5 promulgated thereunder against us and certain of our current and former officers and directors on behalf of all persons or entities who purchased or otherwise acquired Silver Run or AMR securities between March 24, 2017, and February 25, 2019.The new claims are based upon alleged misstatements contained in our proxy statement and made after the Business Combination. The plaintiffs seek compensatory and/or rescissory damages against the defendants.

The outcome of the above securities class action complaints is uncertain, and while we believe that we have valid defenses to the plaintiff's claims and intend to defend the lawsuits vigorously, no assurance can be given as to the outcome of the lawsuits.

On March 1, 2017, Mustang Gas Products, LLC ("Mustang") filed suit in the District Court of Kingfisher County, Oklahoma, against Oklahoma Energy Acquisitions, LP, and eight other entities, including certain of our affiliates and subsidiaries. Mustang alleges that (1) Mustang is a party to gas purchase agreements with Oklahoma Energy containing gas dedication covenants that burden land, leases and wells in Kingfisher County, Oklahoma, and (2) Oklahoma Energy, in concert with the other defendants, has wrongfully diverted gas sales to KFM in contravention of these agreements. Mustang asserts claims for declaratory judgment, anticipatory repudiation and breach of contract against Oklahoma Energy only. Mustang also claims tortious interference with contract, conspiracy, and unjust enrichment/constructive trust against all defendants. We believe that the allegations contained in this lawsuit are without merit and intend to vigorously defend ourselves.

In August 2017, Biloxi Marsh Lands ("Biloxi") filed suit in the 34th District Court for the Parish of St. Bernard, Louisiana, against Meridian Resource & Exploration LLC (a subsidiary of HMI), Alta Mesa, and other defendants. Biloxi alleges negligent construction, installation, maintenance, use and operation of a pipeline. In lieu of litigating corporate structure allegations and to reduce potential litigation expenses, Alta Mesa stipulated with respect to Biloxi that it would be bound by and assume liability and responsibility for any unpaid debts, obligations or final judgments that may be entered against Meridian in favor of Biloxi in this matter.However, these allegations relate to non-STACK oil and gas assets that Alta Mesa distributed to a

subsidiary of HMI prior to the Business Combination. In connection with that distribution, certain HMI subsidiaries agreed to indemnify and hold Alta Mesa harmless from any liabilities associated with those non-STACK oil and gas assets, regardless of when those liabilities arose. Consequently, we believe that any potential damages incurred by Alta Mesa or Meridian as a result of these allegations are the responsibility of HMI. There is no guarantee that HMI will pay any settlement amounts or judgments rendered against Alta Mesa or Meridian. In addition, Alta Mesa's ability to collect any amounts due pursuant to these indemnification obligations will depend upon the liquidity and solvency of HMI.

SEC Investigation

The SEC is conducting a formal investigation into, among other things, the facts involved in the material weakness in our internal controls over financial reporting and the impairment charge disclosed elsewhere in our financial statements. We are cooperating with this investigation. At this point we are unable to predict the timing or outcome of this investigation. If the SEC determines that violations of the federal securities laws have occurred, the agency has a broad range of civil penalties and other remedies available, some of which, if imposed on us, could be material to our business, financial condition or results of operations.

Other contingencies

We are subject to legal proceedings, claims and liabilities arising in the ordinary course of business, the outcomes of which cannot be reasonably estimated. Accruals for losses associated with litigation are made when losses are deemed probable and can be reasonably estimated. Because legal proceedings are inherently unpredictable and unfavorable resolutions could occur, assessing contingencies is highly subjective and requires judgments about uncertain future events. When evaluating contingencies, the Company may be unable to provide a meaningful estimate due to a number of factors, including the procedural status of the matter in question, the presence of complex or novel legal theories, and/or the ongoing discovery and development of information important to the matters.

Performance appreciation rights.

Our Predecessor had a plan that was intended to provide incentive compensation to key employees and consultants. We canceled all amounts due under the plan at the time of the Business Combination, but recognized and paid $10.9 million as strategic costs in G&A during the Successor Period.

NOTE 19 — EMPLOYEE BENEFIT PLANS

We sponsor a 401(k) savings plan, whereby the employees can elect to make contributions. We make matching contributions equal to 100% of the first 5% of an employee's contributions. Employee contributions are immediately vested whereas company matching contributions vest 50% after two years and become fully vested after three years. Company matching contributions were approximately $1.1 million, $0.3 million, $1.2 million and $1.1 million for the Successor Period, the 2018 Predecessor Period, 2017 and 2016, respectively.

NOTE 20 — SIGNIFICANT CONCENTRATIONS, RISKS AND UNCERTAINTIES

We had an agreement with ARM Energy Management, LLC ("ARM") pursuant to which they marketed our oil, gas and NGLs. The sales were generally made under short-term contracts with month-to-month pricing based on published regional indices, adjusted for transportation, location and quality. ARM collected payments from purchasers, deducted their fee and remitted the balance to us. In addition, ARM marketed our firm transportation on the ONEOK Gas Transportation, L.L.C. system and the Panhandle Eastern Pipeline Company, LP system for a management fee. The AM Contributor owns 10% of ARM. During the Successor Period, we paid ARM $1.4 million for our share of the marketing fees. Receivables from ARM for sales on our behalf were $43.8 million and $22.4 million as of December 31, 2018 and 2017, respectively. During the Successor Period, the 2018 Predecessor Period and the years ended December 31, 2017 and 2016, sales managed by ARM on our behalf were $36.2 million, $28.8 million, $199.2 million and $114.8 million, respectively.

Effective as of June 1, 2019, we have terminated our oil and NGL marketing agreement with ARM and will market such products internally. We have extended the term of our gas marketing agreement with ARM through November 30, 2019. With respect to gas sales, ARM continues to collect payments from purchasers, deducts their marketing fee and remits the balance to us.

Additionally, ARM provides us with strategic advice, execution and reporting services with respect to our derivatives activities.Fees paid to ARM for these services were $0.8 million, $0.1 million, $0.8 million and $1.9 million during the Successor Period, 2018 Predecessor Period, 2017 and 2016, respectively.

We believe that the loss of any of our customers, or of our marketing agent ARM, would not have a material adverse effect on us because alternative purchasers are readily available.

Our business makes us vulnerable to changes in wellhead prices of oil and gas. Historically, world-wide oil and gas prices and markets have been volatile, and may continue to be volatile in the future. In particular, spot and future estimated commodity prices declined sharply during the fourth quarter of 2018. Prices for oil and gas can fluctuate widely in response to relatively minor changes in the global and regional supply of and demand for oil and gas, as well as market uncertainty, economic conditions and a variety of additional factors. The duration and magnitude of changes in oil and gas prices cannot be predicted. Sustained low oil or gas prices may require us to further write down the value of our oil and gas properties and/or revise our development plans, which may cause certain undeveloped well locations to be less valuable. This could cause a reduction in the borrowing base under our credit facilities to the extent that we are not able to replace the reserves that we produce. Low prices may also reduce our cash available for distribution, acquisitions and for servicing our indebtedness. We mitigate some of this vulnerability by entering into derivatives.

NOTE 21 — STOCKHOLDERS' EQUITY AND PARTNERS' CAPITAL

Class A Common Stock

Holders of our Class A Common Stock are entitled to one vote for each share held on all matters to be voted on by our stockholders. Holders of the Class A Common Stock and holders of the Class C Common Stock constitute a single class for all stockholder votes. There is no cumulative voting with respect to the election of directors, with the result that the holders of more than 50% of the shares voted for the election of directors can elect all of the directors (subject to the right of the holders of our Series A Preferred Stock and Series B Preferred Stock to nominate and elect up to five directors in total).

In the event of our liquidation or dissolution, the holders of the Class A Common Stock are entitled to share ratably in all assets remaining after payment of liabilities and after provision is made for each class of stock, if any, having preference over the Class A Common Stock. Our stockholders have no preemptive or other subscription rights. There are no sinking fund provisions applicable to the Class A Common Stock.

In August 2018, the Board of Directors authorized up to $50.0 million for the repurchase of our outstanding Class A Common Stock, exclusive of any fees, commissions or other expenses related to such repurchases. Repurchases could be made at the Company's discretion in open market or private transactions. The authorization has no expiration date. We repurchased and retired 3,101,510 shares of Class A Common Stock, which remain authorized and are available for reissuance at a future date. The price paid for the shares repurchased, including commissions, that was in excess of par value has been recorded as a reduction of approximately $14.8 million in additional paid in capital. To fund the repurchase of our Class A shares of Common Stock, the Company sold 3,101,510 of its SRII Opco Common Units to SRII Opco for the same price paid to the market for the Class A shares repurchased. This resulted in an increase during the Successor Period in the ownership position of the noncontrolling interest holders in SRII Opco, and an offsetting reduction in the Company's additional paid in capital, totaling approximately $10.8 million.

Class C Common Stock

In connection with the Business Combination, we issued 213,402,398 shares of Class C Common Stock to the Contributors, 202,169,576 of which remain outstanding as of December 31, 2018.

Holders of Class C Common Stock, voting as a separate class, are entitled to approve any amendment of our certificate of incorporation that would alter or change the rights and powers of the Class C Common Stock. Holders of Class C Common Stock are not entitled to any dividends and are not entitled to receive any of our assets in the event of our liquidation or dissolution.

Shares of Class C Common Stock may be issued only to the Contributors, their respective successors and assigns, as well as any permitted transferees of the Contributors. A holder of Class C Common Stock may transfer shares of Class C Common Stock to any transferee (other than the Company) only if such holder also simultaneously transfers an equal number of such

holder's SRII Opco Common Units to such transferee in compliance with the amended and restated limited partnership agreement of SRII Opco. The Contributors generally have the right to cause SRII Opco to redeem all or a portion of their SRII Opco Common Units in exchange for shares of our Class A Common Stock or, at SRII Opco's option, an equivalent amount of cash. The Company may, however, at its option, effect a direct exchange of cash or Class A Common Stock for such SRII Opco Common Units in lieu of such a redemption by SRII Opco. Upon the future redemption or exchange of SRII Opco Common Units held by a Contributor, a corresponding number of shares of Class C Common Stock will be canceled. During the Successor Period, we issued 2,752,312 and 9,588,764 shares of our Class A Common Stock to equity owners of the AM Contributors and KFM Contributors, respectively, and canceled 12,341,076 shares of our Class C Common Stock as a result of the direct exchange of SRII Opco Common Units redemption.

Redeemable Series A Preferred Stock

As of December 31, 2018, Bayou City Energy Management LLC ("Bayou City") and HPS Investment Partners, LLC ("HPS") each own one of the two outstanding shares of our Series A Preferred Stock, and may not transfer the Series A Preferred Stock or any rights, powers, preferences or privileges thereunder except to an affiliate. AM Equity Holding, LP ("AM Management") elected to redeem their one share for par value in December 2018. The holders of the Series A Preferred Stock are not entitled to vote on any matter on which stockholders generally are entitled to vote. In addition, the holders are not entitled to dividends. The Series A Preferred Stock is not convertible into any other of our securities, but will be redeemable by us for par value upon the earlier to occur of (1) the fifth anniversary of the Closing Date, (2) the optional redemption of such Series A Preferred Stock at the election of the holder thereof or (3) upon a breach of the transfer restrictions described above. If the Series A Preferred Stock remains outstanding, its holders are entitled to nominate and elect up to two directors to our board of directors for a period of up to five years following the closing of the Business Combination based on their and their affiliates' beneficial ownership of common stock.

Redeemable Series B Preferred Stock

As of December 31, 2018, the Riverstone Contributor owns the only outstanding share of our Series B Preferred Stock, and may not transfer the Series B Preferred Stock or any rights, powers, preferences or privileges thereunder except to an affiliate (as defined in the limited partnership agreement of SRII Opco). The holder of the Series B Preferred Stock is not entitled to vote on any matter on which stockholders generally are entitled to vote. In addition, the holder is not entitled to dividends. The Series B Preferred Stock is not convertible into any other security of the Company, but will be redeemable by us for par value upon the earlier to occur of (1) the fifth anniversary of the Closing Date, (2) the optional redemption of such Series B Preferred Stock at the election of the holder thereof or (3) upon a breach of the transfer restrictions described above. If the Series B Preferred Stock remains outstanding, its holder is entitled to nominate and elect up to three directors to our board of directors for a period of up to five years following the closing of the Business Combination based on its and its affiliates' beneficial ownership of common stock.

Warrants

As of December 31, 2018, we had 62,966,651 warrants outstanding, consisting of 34,499,985 public warrants originally sold in our IPO ("Public Warrants"), 15,133,333 Private Placement Warrants sold to our Sponsor and 13,333,333 Forward Purchase Warrants issued to Riverstone VI SR II Holdings, LP.

Each Public Warrant entitles the holder to purchase one share of our Class A Common Stock for $11.50 and expire in February 2023.

The Private Placement Warrants are identical to the Public Warrants, except the Private Warrants are non-redeemable so long as they are held by our Sponsor or its permitted transferees.

The Forward Purchase Warrants have terms and provisions that are identical to those of the Private Placement Warrants, except the Forward Purchase Warrants are non-redeemable so long as they are held by our Sponsor or its permitted transferees. The Forward Purchase Warrants were sold in a private placement pursuant to a purchase agreement between us and our Sponsor.

Noncontrolling Interest

NCI relates to SRII Opco Common Units that were originally issued to the AM Contributor, the KFM Contributor and the Riverstone Contributor in connection with the Business Combination and continue to be held by holders other than the

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Company. At the date of the Business Combination, the noncontrolling interest owners held55.8% (AM Contributor 36.2%, KFM Contributor 14.4%, and Riverstone Contributor 5.2%) of the limited partner interests in SRII Opco. The non-controlling interest percentage is affected by Class C Common Stock conversions and the Class A Common Stock activities after which, the noncontrolling interest owners held approximately53.0% of the limited partner interests in SRII Opco as ofDecember 31, 2018.

Partnership Management and Control

Alta Mesa's amended and restated partnership agreement provides for interests to be divided into economic units held by the partners referred to as "LP Units" and non-economic general partner interests owned by Alta Mesa GP referred to as "GP Units". Alta Mesa GP owns all the GP Units and SRII Opco owns all the LP Units.

Since Alta Mesa is a limited partnership, its operations and activities are managed by the board of directors of its general partner, Alta Mesa GP. The limited liability company agreement of Alta Mesa GP provides for two classes of interests: (i) Class A Units, which hold100% of the economic rights in Alta Mesa GP and (ii) Class B Units, which hold100% of the voting interests in Alta Mesa GP.

SRII Opco is the sole owner of Alta Mesa GP's Class A Units and owns 90% of the Class B Units. Our former President and Chief Executive Officer and our former Chief Operating Officer—Upstream, along with certain affiliates of Bayou City and HPS, own an aggregate10% of the Class B Units. Alta Mesa GP's board of directors are selected by the Class B members. Notwithstanding the foregoing, voting control of Alta Mesa GP is vested in SRII Opco pursuant to a voting agreement.

NOTE 22 — EQUITY-BASED COMPENSATION (Successor)

We have adopted the Alta Mesa Resources, Inc. 2018 Long Term Incentive Plan (the "LTIP"). A total of50,000,000 shares of Class A Common Stock are reserved for issuance under the LTIP. The LTIP provides for the grant of stock awards, including incentive stock options ("ISOs"), nonqualified stock options ("NSOs"), stock appreciation rights ("SARs"), restricted stock, dividend equivalents, restricted stock units ("RSUs") and other awards in our Class A Common Stock. Prior to the Business Combination, we had no equity-based compensation programs. During the Successor Period, the Company recognized stock-based compensation expense of$22.0 million in general and administrative expense including accelerated vesting for separated executives related to the LTIP.

Stock options

Stock options expire seven years from the grant date and generally vest in one-third increments each year, based on continued employment. Employees have 90 days after termination to exercise vested stock options, unless extended by an employment agreement.

?	Successor				
?	Stock Options	Weighted Average Exercise Price	Weighted Average Grant-Date Fair Value	Weighted Average Remaining Term (in years)	Aggregate Intrinsic Value (in thousands)
Outstanding as of February 9, 2018	—	$ —	$ —	—	—
Granted	5,283,224	8.80	4.33	—	—
Exercised	—	—	—	—	—
Forfeited or expired	(139,319)	9.38	4.55	—	—
Outstanding as of December 31, 2018	5,143,905	$ 8.79	$ 4.33	5.30	$ —
Vested at December 31, 2018 or expected to vest in future	5,143,905	$ 8.79	$ 4.33	5.30	—
Exercisable as of December 31, 2018	1,509,435	$ 9.54	$ 4.62	3.00	$ —

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The following assumptions were used to determine the fair value of our 2018 option grants:

?	Successor February 9, 2018 Through December 31, 2018
Expected term (in years)	4.5
Expected stock volatility	64.6%
Dividend yield	—
Risk-free interest rate	2.5%

Unrecognized compensation cost related to non-vested stock options at December 31, 2018, was $11.0 million, which we expect to recognize over a weighted average remaining period of 1.7 years.

Restricted stock

Restricted stock granted to employees generally vests in one-third increments each year based on continued employment. Prior to vesting, unvested restricted stock may not be traded but is entitled to accumulate any dividend value. During the period from February 9, 2018 to December 31, 2018, the Company granted 98,199 shares to certain of its directors, all which vested immediately, and 2,140,160 restricted stock awards to employees.

The following table provides information about restricted stock awards granted during the Successor Period:

?	Successor	
?	Restricted Stock Awards	Weighted Average Grant Date Fair Value per share
Outstanding as of February 9, 2018	—	$ —
Granted	2,238,359	7.54
Vested [(1)]	(384,413)	8.40
Forfeited or expired	(61,935)	8.80
Outstanding as of December 31, 2018	1,792,011	$ 7.32

(1) To satisfy minimum tax withholding, 94,576 shares were withheld.

Unrecognized compensation cost related to unvested restricted shares at December 31, 2018 was $9.5 million, which we expect to recognize over a weighted average remaining period of 1.6 years.

Restricted stock units

Performance-based restricted stock units ("PSUs") granted in 2018 generally vest over three years at 20% during the first year, 30% during the second year and 50% during the third year. The number of PSUs vesting each year will be based on the achievement of annual performance goals and objectives applicable to each respective year of vesting. Based on achievement of those goals and objectives, the number of PSUs that vest can range from 0% to 200% of the target grant applicable to each vesting period. We only recognize expense for PSUs when the specified performance thresholds for future periods have been established. For PSUs granted during the Successor Period only the performance goals and objectives for 2018 had been established as of December 31, 2018. Those 2018 performance goals were not attained, and the 2018 award tranche was forfeited, except with respect to separations involving employment agreements whereby the separated employee was eligible to receive the award granted. No amounts will be recognized for the 2019 and 2020 performance periods until the specific targets have been established and probability of attainment can be measured. The targets for 2019 were established in March 2019 and the targets for 2020 remain undetermined.

The following summary provides information about the target number of PSUs granted during the Successor Period:

?	Successor	
?	PSUs	Weighted Average Grant Date Fair Value per unit
Outstanding as of February 9, 2018	—	$ —
Granted	2,093,453	4.07
Vested (1)	(1,559,749)	2.53
Forfeited or expired	(533,704)	8.54
Outstanding as of December 31, 2018	—	$ —

(1) To satisfy minimum tax withholding, 388,655 shares were withheld.

As of December 31, 2018, there was no unrecognized compensation cost related to unvested PSUs.

NOTE 23 — INCOME TAXES

As a result of the Business Combination, the Company's wholly owned subsidiary, SRII Opco GP, is the general partner of SRII Opco, which became the sole managing member of Alta Mesa GP and KFM, and as a result, we began consolidating the financial results of Alta Mesa and KFM. SRII Opco is treated as a partnership for U.S. federal and most applicable state and local income tax purposes. As a partnership, SRII Opco is not subject to U.S. federal and certain state and local income taxes. Any taxable income or loss generated by SRII Opco is passed through to and included in the taxable income or loss of its limited partners, including the Company, on a pro rata basis. The Company is subject to U.S. federal income taxes, in addition to state and local income taxes, with respect to its allocable share of any taxable income or loss of SRII Opco, as well as any stand-alone income or loss generated by the Company.

Income tax expense (benefit) included in the consolidated statements of operations is detailed below:

?	Successor
(in thousands)?	**February 9, 2018 Through December 31, 2018**
Current taxes:	
Federal	$ (69)
State	—
?	(69)
Deferred taxes:	
Federal	—
State	—
?	—
Income tax expense (benefit)	$ (69)

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A reconciliation of the statutory federal income tax expense to the income tax expense from continuing operations for the Successor Period is as follows:

?	Successor		
(Amounts in thousands)?	February 9, 2018 Through December 31, 2018		
Federal income tax expense (benefit) - at statutory rate	$	(682,378)	21.00 %
State income taxes - net of federal income tax benefit		(154,022)	4.74
Non-controlling interest		833,239	(25.64)
Return to provision - amended 2017 return reduction to current tax expense		(71)	—
Change in valuation allowance		3,135	(0.10)
Permanent items		25	—
Other		3	—
Income tax expense (benefit)	$	(69)	— %

The tax effects of temporary differences that give rise to significant positions of the deferred income tax assets and liabilities are presented below:

?	Successor	
(in thousands)?	February 9, 2018 Through December 31, 2018	
Deferred tax asset:		
Investment in SRII Opco, LP	$	269,846
NOL carryforward		101,337
Organizational/startup costs		154
Other		11
Total deferred tax assets		371,348
Less: valuation allowance		(371,348)
Net deferred tax assets		—
Deferred tax liability		—
Total net deferred tax assets/(liabilities)	$	—

For the year ended December 31, 2018, the change in the valuation allowance was$370.9 million.

In connection with the Business Combination, we entered into the Tax Receivable Agreement with SRII Opco, the AM Contributor, and the Riverstone Contributor. This agreement generally provides for the payment by us of85% of the amount of net cash savings, if any, in income tax that we actually realize (or are deemed to realize in certain circumstances) in periods after the Business Combination as a result of (i) tax basis increases resulting from the exchange of SRII Opco Common Units for AMR Class A Common Stock and (ii) interest paid or deemed to be paid by us as a result of, and additional tax basis arising from, any payments we make under the Tax Receivable Agreement. We will retain the benefit of the remaining 15% of these cash savings.

The payment obligations under the Tax Receivable Agreement are obligations of the Company and not obligations of SRII Opco, and the payments required could be substantial. For purposes of the Tax Receivable Agreement, cash savings in tax generally are calculated by comparing our actual tax liability to the amount we would have been required to pay had we not been entitled to any of the tax benefits subject to the Tax Receivable Agreement. In other words, we would calculate our federal, state and local income tax liabilities as if no tax attributes arising from a redemption or direct exchange of SRII Opco Common Units had been transferred to us. The term of the Tax Receivable Agreement continues until all such tax benefits have been utilized or have expired, unless we exercise our right to terminate the Tax Receivable Agreement or the Tax Receivable Agreement is otherwise terminated.

As of December 31, 2018, there has been one exchange of SRII Common Units which would trigger a payment under the TRA. This exchange occurred in November 2018 when 2,752,312 SRII Opco Common Units were converted into the same number of shares of AMR Class A Common Stock. We have calculated the tax basis increase resulting from this exchange, and the resulting potential future net cash income tax savings multiplied by 85% to arrive at a potential Tax Receivable Agreement liability. This amount would be due and payable by us if we actually realized these future cash tax savings. However, as of December 31, 2018 we have recorded a full valuation allowance on our other deferred tax assets determined in accordance with GAAP, and therefore we have not realized any savings and have recorded no liability for such at this time.We are highly unlikely to recognize these attributes in 2019.

NOTE 24 — RELATED PARTY TRANSACTIONS

On August 31, 2015, Alta Mesa's wholly owned subsidiary Oklahoma Energy entered into a Crude Oil Gathering Agreement (the "Crude Oil Gathering Agreement") and Gas Gathering and Processing Agreement (the "Gas Gathering and Processing Agreement") with KFM. The Gas Gathering and Processing Agreement was subsequently amended in February 2017, effective December 2016, and again in June 2018, effective April 2018. The more recent amendment to the Gas Gathering and Processing Agreement impacts our ability to make elections with respect to the NGL portion of our production volumes but has no other effect on our consolidated financial statements.

David Murrell, our Vice President of Land and Business Development, is the principal of David Murrell & Associates, which provided land consulting services to us until termination of our contract in December 2018. The primary employee of David Murrell & Associates was his spouse, Brigid Murrell. Services were provided at a pre-negotiated hourly rate based on actual time utilized by Alta Mesa.Total expenditures under this arrangement were approximately $166,000, $28,000, $186,000, and $146,000 for the Successor Period, the2018 Predecessor Period, and the years ended December 31, 2017 and 2016, respectively. Following termination of the contract, Brigid Murrell continued to provide services to the Company as an individual contractor and was paid $8,523 for services rendered in that capacity through December 31, 2018. These amounts are included in general and administrative expense.

David McClure, our former Vice President of Facilities and Infrastructure, and the son-in-law of our former President and Chief Executive Officer, Harlan H. Chappelle, received total compensation of approximately $1,157,774, $28,874, $250,000, and $425,000 for the Successor Period, the 2018 Predecessor Period, and the years ended December 31, 2017 and 2016, respectively. These amounts are included in general and administrative expense.

David Pepper, Surface Land Manager for KFM, and the cousin of our Vice President of Land and Business Development, David Murrell, received total compensation of approximately $297,134, $67,322, $150,000, and $180,000 for the Successor Period, the2018 Predecessor Period, and the years ended December 31, 2017 and 2016, respectively. These amounts are included in general and administrative expense.

Bayou City Agreement

In January 2016, Oklahoma Energy entered into a Joint Development Agreement, as amended on June 10, 2016 and December 31, 2016, (the "JDA"), with BCE, a fund advised by Bayou City, to fund a portion of Alta Mesa's drilling operations and to allow Alta Mesa to accelerate development of our STACK acreage. The JDA establishes a development plan of 60 wells in three tranches, and provides opportunities for the parties to potentially agree to an additional 20 wells. Pursuant to the JDA, BCE committed to fund 100% of Alta Mesa's working interest share up to a maximum average well cost of $3.2 million in drilling and completion costs per well for any tranche. Alta Mesa is responsible for any drilling and completion costs exceeding approved amounts. BCE may request refunds of certain advances from time to time if funded wells previously on the drilling schedule were subsequently removed. In exchange for funding the drilling and completion costs, BCE receives 80% of our working interest in each wellbore, which BCE interest will be reduced to 20% of our initial working interest upon BCE achieving a 15% internal rate of return on the wells within a tranche and automatically further reduced to 12.5% of our initial interest upon BCE achieving a 25% internal rate of return. Following the completion of each joint well, Alta Mesa and BCE will each bear its respective proportionate working interest share of all subsequent operating costs related to such joint well. Mr. William McMullen, one of our directors, is founder and managing partner of BCE. The approximate dollar value of the amount involved in this transaction, or Mr. McMullen's interests in the transaction, depends on a number of factors outside his control and is not known at this time. During the 2018 Predecessor Period, BCE advanced us approximately $39.5 million to drill wells under the JDA. As of December 31, 2018, 61 joint wells have been drilled or spudded.As of December 31, 2018 and December 31, 2017, $9.8 million and $23.4 million, respectively of revenue and net advances remaining from BCE for their working interest share of the drilling and development costs arising under the JDA were included as "Advances from

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related party" in our consolidated balance sheets. At December 31, 2018, there were no funded horizontal wells in progress, and we do not expect any wells to be developed in 2019 pursuant to the JDA. On June 11, 2019, we received a letter from BCE noticing us of alleged defaults under the JDA. We dispute these allegations and intend to vigorously defend ourselves.

High Mesa

In September 2017, Alta Mesa entered into a $1.5 million promissory note receivable with its affiliate Northwest Gas Processing, LLC, which obligation was subsequently transferred to High Mesa Services, LLC ("HMS"), a subsidiary of HMI.The promissory note bears interest, which may be paid-in-kind and added to the principal amount, at a rate of 8% per annum and matured in February 2019. At December 31, 2018 and 2017, amounts due under the promissory note totaled $1.7 million and $1.5 million, respectively. HMS defaulted under the terms of that promissory note when it was not paid when due on February 28, 2019, and HMS has failed to cure such default. Alta Mesa subsequently declared all amounts owing under the note immediately due and payable. Alta Mesa also has an $8.5 million promissory note receivable from HMS which matures on December 31, 2019, and bears interest at 8% per annum, which may be paid-in-kind and added to the principal amount. As of December 31, 2018, and 2017, the note receivable amounted to $11.7 million and $10.8 million, respectively. HMI disputes its obligations under the $1.5 million note and $8.5 million note referenced above as payable to Alta Mesa. We oppose HMI's claims and believe HMI's obligation under the notes to be valid assets of Alta Mesa and that the full amount is payable to Alta Mesa. We are pursuing remedies under both promissory notes and under applicable law in connection with repayment of the promissory note by HMS. As a result of the potential conflict of interest of certain of our directors who are also controlling holders and directors of HMI, our disinterested directors will address any potential conflicts of interest with respect to this matter. As of December 31, 2018, we established an allowance for doubtful accounts for the promissory notes totaling $13.4 million, the expense for which is included in general and administrative expense in 2018.

Interest income on the promissory notes amounted to approximately $0.9 million, $0.1 million, $0.9 million, and $0.8 million for the Successor Period, the 2018 Predecessor Period, and the years ended December 31, 2017 and 2016, respectively, all recorded as paid-in-kind and added to the balance due thereunder.

In connection with the Business Combination, Alta Mesa distributed its non-STACK oil and gas assets to a subsidiary of HMI, and certain subsidiaries of HMI agreed to indemnify and hold Alta Mesa harmless from any liabilities associated with those non-STACK oil and gas assets, regardless of when those liabilities arose. Under the High Mesa Agreement, during the 180-day period following the Closing (the "Initial Term"), we agreed to provide certain administrative, management and operational services necessary to manage the business of HMI and its subsidiaries (the "Services"). Thereafter, the High Mesa Agreement automatically renewed for additional consecutive 180-day periods (each a "Renewal Term"), unless terminated by either party upon at least 90-days written notice to the other party prior to the end of the Initial Term or any Renewal Term. As compensation for the Services, HMI agreed to pay us each month (i) a management fee of $10,000 and (ii) an amount equal to any and all costs and expenses incurred in connection with providing the Services.

Although the automatic renewal of this agreement occurred in the third quarter of 2018, the parties subsequently reached agreement to terminate the High Mesa Agreement effective January 31, 2019. Through April 1, 2019, we were obligated to take all actions that HMI reasonably requested to effect the transition of the Services from Alta Mesa to a successor service provider. During the transition period, HMI agreed to pay us (i) for all Services performed, (ii) an amount equal to our costs and expenses incurred in connection with providing the Services as provided for in the approved budget and (iii) an amount equal to our costs and expenses reimbursable pursuant to the High Mesa Agreement. Prior to 2018, we also incurred $0.8 million of costs for the direct benefit of HMI and the non-STACK assets, outside of the High Mesa Agreement, and pursuant to the High Mesa Agreement have reflected these costs as "Related party receivables" in the balance sheets. As of December 31, 2018 and December 31, 2017, we had receivables of approximately $10 million and $0.8 million, for costs and expenses incurred on HMI's behalf. Subsequent to year-end, we billed HMI $0.9 million for incremental MSA costs incurred and have received approximately $1.0 million in payments. HMI has disputed certain of these amounts billed by Alta Mesa. We are pursuing remedies under applicable law in connection with repayment of this receivable. There is no guarantee that HMI will pay the amounts it owes. In addition, our ability to collect these amounts or future amounts that may become due pursuant to indemnification obligations may be adversely impacted by liquidity and solvency issues at HMI. As a result, we have recognized an allowance for uncollectible accounts of $9.0 million to fully provide for the unremitted balance and may have future allowances for amounts incurred in 2019 prior to the termination of the MSA. We also may be subject to liabilities for the non-STACK oil and gas assets for which we should have been indemnified. We currently cannot estimate the extent of such liabilities.

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NOTE 25 — BUSINESS SEGMENT INFORMATION

Following the Business Combination, we have two reportable segments: (i) Upstream and (ii) Midstream Each segment is ultimately led by the Company's Chief Executive Officer, who is also the Chief Operating Decision Maker ("CODM"). The CODM evaluates segment performance using Adjusted EBITDAX and Adjusted EBITDA.

We believe Adjusted EBITDAX and Adjusted EBITDA are useful because it allows users to more effectively evaluate our operating performance, compare the results of our operations from period to period and against our peers without regard to our financing methods or capital structure and because it highlights trends in our business that may not otherwise be apparent when relying solely on GAAP measures. Adjusted EBITDAX and Adjusted EBITDA should not be considered as an alternative to net income (loss), operating income (loss) or any other performance measure derived in accordance with GAAP and may not be comparable to similarly titled measures in other companies' reports.

During the Predecessor Periods, all of the Company's operations were in the Upstream segment.

The following segment information reflects the retrospective adoption of ASC 606, effectiveFebruary 9, 2018. The adoption of ASC 606 had no impact on the Predecessor Periods.

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?	Successor			
?	February 9, 2018 Through December 31, 2018			
(in thousands)	**Exploration & Production**	**Midstream**	**Corporate and Eliminations**	**Total**
Revenue				
Oil	$ 323,299	$ —	$ —	$ 323,299
Natural gas	43,407	—	—	43,407
Natural gas liquids	43,039	—	—	43,039
Sales of gathered production	—	31,506	—	31,506
Midstream revenue	—	68,519	(41,059)	27,460
Segment sales revenue	409,745	100,025	(41,059)	468,711
Other revenue	4,762	—	—	4,762
Operating revenue	414,507	100,025	(41,059)	473,473
Gain on sale of assets	4,751	—	—	4,751
Gain (loss) on derivatives	(10,247)	—	—	(10,247)
Total revenue	409,011	100,025	(41,059)	467,977
Operating expenses				
Lease operating	60,547	—	(3,720)	56,827
Transportation, processing and marketing	50,038	9,911	(40,656)	19,293
Midstream operating	—	15,221	—	15,221
Cost of sales for purchased gathered production	—	31,247	—	31,247
Production taxes	16,865	—	—	16,865
Workovers	5,563	—	—	5,563
Exploration	34,085	—	—	34,085
Depreciation, depletion, and amortization	133,554	27,388	—	160,942
Impairment of assets	2,033,712	1,171,339	—	3,205,051
General and administrative	114,735	14,025	2,292	131,052
Total operating expenses	2,449,099	1,269,131	(42,084)	3,676,146
Operating income	(2,040,088)	(1,169,106)	1,025	(3,208,169)
Other income (expense)				
Interest expense	(38,265)	(5,031)	—	(43,296)
Interest income and other	1,983	6	60	2,049
Total other income (expense)	(36,282)	(5,025)	60	(41,247)
Income (loss) from continuing operations before income taxes	(2,076,370)	(1,174,131)	1,085 [1]	(3,249,416)
Interest expense	38,265	5,031	—	43,296
Gain on unrealized hedges	(28,714)	—	—	(28,714)
Loss on sale of fixed assets	388	—	—	388
Depreciation, depletion and amortization	133,554	27,388	—	160,942
Impairment of assets	2,033,712	1,171,339	—	3,205,051
Provision for uncollectible related party receivables	22,438	—	—	22,438
Equity-based compensation	20,000	1,190	835	22,025
Exploration	34,085	—	—	34,085
EBITDAX	177,358	30,817	1,920	210,095
Business Combination related expense	23,717	—	—	23,717

Adjusted EBITDAX	$ 201,075	$ 30,817	$ 1,920	$ 233,812
Equity method investment	$ —	$ 1,100	$ —	$ 1,100
Capital expenditures	700,953	61,807	—	762,760

(1) Includes $3,316 for elimination of intercompany deferred revenue resulting from the adoption of ASC 606.

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The following table summarizes total assets by segment:

?	Successor			
?	December 31, 2018			
(in thousands)	**Upstream**	**Midstream**	**Eliminations**	**Total**
Total segment assets	$ 935,719	$ 437,721	$ (21,158)	$ 1,352,282
Corporate assets				5,548
Total assets				$ 1,357,830

NOTE 26 — SUBSEQUENT EVENTS

We implemented reductions in force in 2019 that will cause us to incur expenses of$4.7 million in the first quarter and $1.2 million in the second quarter. This also resulted in a partial termination of our 401(k) savings plan, which accelerated vesting for impacted employees.

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NOTE 27 — SUPPLEMENTAL QUARTERLY INFORMATION (Unaudited)

	Predecessor	Successor			
2018 (in thousands)	**January 1, 2018 Through February 8, 2018**	**February 9, 2018 Through March 31, 2018**	**June 30**	**Sept 30**	**Dec 31**
Total revenue, as originally reported	$ 47,434	$ 45,870	$ 93,137	$ 153,651	$ 221,139
Other adjustments	205	(205)	—	—	—
Effect of adoption of ASC 606	—	(4,647)	(10,937)	(13,847)	(16,389)
Total revenue, as revised	$ 47,639	$ 41,018	$ 82,200	$ 139,804	$ 204,955
Operating income (loss), as originally reported	$ (1,807)	$ (32,464)	$ (15,063)	$ 31,372	$ (3,190,347)
Other adjustments	30	(30)	—	—	—
Effect of adoption of ASC 606	—	(236)	(439)	(478)	(514)
Operating income (loss), as revised	$ (1,777)	$ (32,730)	$ (15,502)	$ 30,894	$ (3,190,831)
Income (loss) from continuing operations, as originally reported [(1)(2)(3)]	$ (7,146)	$ (33,549)	$ (22,340)	$ 17,755	$ (3,209,546)
Other adjustments	30	(30)	—	—	—
Effect of adoption of ASC 606	—	(175)	(326)	(355)	(811)
Income (loss) from continuing operations, as revised	$ (7,116)	$ (33,754)	$ (22,666)	$ 17,400	$ (3,210,327)
Income (loss) from discontinued operations	$ (7,746)	$ —	$ —	$ —	$ —
Net income (loss), as originally reported	$ (14,892)	$ (33,549)	$ (22,340)	$ 17,755	$ (3,209,546)
Other adjustments	30	(30)	—	—	—
Effect of adoption of ASC 606	—	(175)	(326)	(355)	(811)
Net income (loss), as revised	$ (14,862)	$ (33,754)	$ (22,666)	$ 17,400	$ (3,210,327)
Net income (loss) attributable to Alta Mesa Resources, Inc. stockholders, as originally reported	N/A	$ (13,235)	$ (6,444)	$ 7,135	$ (1,511,372)
Other adjustments	N/A	(17)	—	—	—
Effect of adoption of ASC 606	N/A	(78)	(156)	(162)	(387)
Net income (loss) attributable to Alta Mesa Resources, Inc. stockholders, as revised	N/A	$ (13,330)	$ (6,600)	$ 6,973	$ (1,511,742)
Basic net income (loss) per common share attributable to Alta Mesa Resources, Inc. stockholders, as originally reported	N/A	$ (0.08)	$ (0.04)	$ 0.04	$ (8.53)
Other adjustments	N/A	—	—	—	—
Effect of adoption of ASC 606	N/A	—	—	—	—
Basic net income (loss) per common share attributable to Alta Mesa Resources, Inc. stockholders, as revised	N/A	$ (0.08)	$ (0.04)	$ 0.04	$ (8.53)
Diluted net income (loss) per common share attributable to Alta Mesa Resources, Inc. stockholders, as originally reported	N/A	$ (0.08)	$ (0.04)	$ 0.04	$ (8.53)
Other adjustments	N/A	—	—	—	—
Effect of adoption of ASC 606	N/A	—	—	—	—

Diluted net income (loss) per common share attributable to Alta Mesa Resources, Inc. stockholders, as revised	N/A	$ (0.08)	$ (0.04)	$ 0.04	$ (8.53)

(1) Includes $3.2 billion of impairment expense during the quarter ended December 31, 2018.
(2) Includes $6.7 million and $52.8 million of gains on derivatives during the 2018 Predecessor Period and the quarter ended December 31, 2018, respectively. Includes $22.6 million, $29.2 million and $11.2 million of losses on derivatives during the period from February 9, 2018 through March 31, 2018, and during the quarters ended June 30, 2018 and September 30, 2018, respectively.
(3) Includes $6.0 million gain primarily from the sale of seismic data during the period from February 9, 2018 through March 31, 2018.

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?	Predecessor			
2017 (in thousands)	**March 31**	**June 30**	**Sept 30**	**Dec 31**
Total revenue[1][2]	$ 95,079	$ 79,800	$ 57,923	$ 46,567
Income (loss) from continuing operations[1][2][3]	29,430	15,620	(22,163)	(35,733)
Loss from discontinued operations[4]	(4,515)	(30,934)	(2,041)	(27,325)
Net income (loss)	24,915	(15,314)	(24,204)	(63,058)

(1) Includes $30.2 million and $18.3 million of gains on derivatives during the quarters ended March 31, 2017 and June 30, 2017, respectively, and $10.5 million and $29.7 million of losses on derivatives during the quarters ended September 30, 2017 and December 31, 2017, respectively.
(2) Includes $5.3 million gain on acquisition of oil and gas properties during the quarter ended September 30, 2017, which was reduced by $3.6 million during the quarter ended December 31, 2017.
(3) Includes $1.2 million of impairment expense during the quarter ended March 31, 2017.
(4) The quarter ended December 31, 2017 includes a loss on the sale of assets of $22.2 million, primarily associated with the sale of Weeks Island.

NOTE 28 — SUPPLEMENTAL OIL AND GAS DISCLOSURES (Unaudited)

During January 2019, we finalized our development plan for the next five years and received an audit report from our outside engineers that agreed with our recognition of PUDs for the majority of that future development. During April 2019, in finalizing our financial reporting for 2018, we determined that we may fail to satisfy the leverage covenant under the Alta Mesa RBL during 2019. Accordingly, we were unable to conclude that we would have a high likelihood of continued access to that capital source. Thus, we concluded that we did not satisfy the ability-to-drill threshold under the SEC's reserve recognition rule with respect to our future drilling locations and did not recognize any proved undeveloped locations in our final December 31, 2018 reserve report received in April 2019. Should our ability to fund the required development costs improve in the future, we expect to recognize all or a portion of those resources as proved.

The unaudited reserve and other information presented below is provided as supplemental information. The information presented during the Predecessor Periods includes amounts related to discontinued operations.

Reserve estimates are inherently imprecise and estimates of new discoveries are less precise than those of producing oil and gas properties. Accordingly, these estimates are expected to change as future information becomes available. Under our gathering contract with KFM, we have options regarding how we accept or reject ethane volumes. Our reserve disclosures that follow assume that we recover (rather than reject) ethane volumes, which generally has the effect of increasing the reserves, with no corresponding increase to value or future cash flow.

Reserve estimates incorporate assumptions regarding future prices and costs at the date estimates are made. Actual future prices and costs may be materially higher or lower. Actual future net revenue will also be affected by factors such as actual production, supply and demand for oil and gas, curtailments or increases in consumption by gas purchasers, changes in governmental regulations or taxation and the impact of inflation on costs.

Oil and gas producing activities are conducted onshore within the continental United States and all of our proved reserves are located within the United States.

Estimated Quantities of Proved Reserves

The following table sets forth our net proved reserves as of the Successor Period, the 2018 Predecessor Period, the years ended December 31, 2017 and 2016, and the changes therein during the periods then ended.

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	Oil (Mbbls)	Gas (MMcf)	NGL's (Mbbls)	Boe (Mbbls)
Total Proved Reserves:				
Balance at December 31, 2015 (Predecessor)	34,142	155,423	18,437	78,483
Production	(4,001)	(13,959)	(956)	(7,284)
Purchases in place (1)	1,508	6,754	613	3,247
Discoveries and extensions	29,903	154,653	14,000	69,679
Sales of reserves in place	(73)	(966)	(10)	(244)
Revisions of previous quantity estimates and other	(3,680)	14,100	(3,794)	(5,124)
Balance at December 31, 2016 (Predecessor)	57,799	316,005	28,290	138,757
Production	(4,850)	(18,218)	(1,387)	(9,274)
Purchases in place	725	4,860	401	1,936
Discoveries and extensions	20,135	108,676	9,640	47,888
Sales of reserves in place	(3,622)	(1,280)	—	(3,836)
Revisions of previous quantity estimates and other	3,331	23,476	(57)	7,187
Balance at December 31, 2017 (Predecessor)	73,518	433,519	36,887	182,658
Production	(521)	(1,984)	(161)	(1,012)
Purchases in place	—	—	—	—
Discoveries and extensions	—	—	—	—
Sales of reserves in place (2)	(1,667)	(24,239)	(771)	(6,478)
Revisions of previous quantity estimates and other	375	3,506	289	1,248
Balance at February 8, 2018 (Predecessor)	71,705	410,802	36,244	176,416
Production(3)	(5,053)	(16,913)	(2,268)	(10,140)
Purchases in place(3)	2,658	13,331	1,751	6,631
Discoveries and extensions(3)	30,026	155,306	19,646	75,557
Sales of reserves in place	—	—	—	—
Revisions of previous quantity estimates and other(3)	(74,064)	(418,378)	(35,581)	(179,375)
Balance at December 31, 2018 (Successor)	25,272	144,148	19,792	69,089
?				
Proved Developed Reserves:				
Balance at December 31, 2015	14,942	71,752	6,958	33,859
Balance at December 31, 2016	16,832	93,361	7,977	40,371
Balance at December 31, 2017	20,347	150,183	12,180	57,557
Balance at February 8, 2018	19,345	126,231	11,348	51,731
Balance at December 31, 2018	25,272	144,148	19,792	69,089
Proved Undeveloped Reserves:				
Balance at December 31, 2015	19,200	83,671	11,479	44,624
Balance at December 31, 2016	40,967	222,644	20,313	98,386
Balance at December 31, 2017	53,171	283,336	24,707	125,101
Balance at February 8, 2018	52,360	284,571	24,896	124,685
Balance at December 31, 2018	—	—	—	—

(1) Purchases in place includes 3.1 MMBoe of reserves related to the Contributed Wells from HMI.
(2) Sales of reserves in place during the 2018 Predecessor Period represent amounts related to our non-STACK properties that were distributed to the AM contributor and are classified as discontinued operations in our consolidated financial statements.
(3) An analysis of changes in our reserves from February 8, 2018 to December 31, 2018 follows:

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Description	MBoe Proved Developed Reserves	Proved Undeveloped Reserves	Total
Balance at February 8, 2018	51,731	124,685	176,416
Production	(10,140)	—	(10,140)
Purchases in place, discoveries and extensions	35,096	47,092	82,188
Revisions of previous quantity estimates and other:			
Lower estimated recoveries identified as a result of 2018 drilling program	(31,964)	(69,534)	(101,498)
Higher average commodity prices in Successor Period compared to 2017	5,367	5,829	11,196
Transfers of PUDs to proved developed reserves	18,999	(18,999)	—
Derecognition of PUDs due to significant concerns about ability to fund development of those reserves	—	(89,073)	(89,073)
Balance at December 31, 2018	69,089	—	69,089

Results of Operations for Oil and Gas Producing Activities - Upstream Segment

?

(in thousands)	Successor February 9, 2018 Through December 31, 2018	Predecessor January 1, 2018 Through February 8, 2018	Year Ended December 31, 2017	Year Ended December 31, 2016
Operating revenue	$ 414,507	$ 40,136	$ 269,386	$ 142,356
Production expense (1)	247,748	30,743	138,833	87,869
Depreciation, depletion and amortization	133,554	11,670	89,115	53,755
Exploration expense	34,085	7,003	13,563	17,230
Impairment expense	2,033,712	—	1,188	382
Income tax expense (benefit)	4	—	6	—
Results of operations	$ (2,034,596)	$ (9,280)	$ 26,681	$ (16,880)

(1) Production expense consists of direct lease operating expense, transportation and marketing expense, production taxes, workover expense and allocated general and administrative expense.

Capitalized Costs Relating to Oil and Gas Producing Activities

?

(in thousands)	December 31, Successor 2018	Predecessor 2017(1)
Capitalized costs:		
Proved properties	$ 2,110,346	$ 1,545,963
Unproved properties	816,282	116,787
Total	2,926,628	1,662,750
Accumulated depreciation, depletion, amortization and impairment	(2,163,291)	(711,275)
Net capitalized costs	$ 763,337	$ 951,475

(1) Includes amounts related to non-STACK assets distributed in the 2018 Predecessor Period and reflected as discontinued operations.

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Costs Incurred in Oil and Gas Acquisition, Exploration and Development Activities

Acquisition costs in the table below include costs incurred to purchase, lease or otherwise acquire property. Exploration expenses include additions to exploratory wells and other exploration expenses, such as geological and geophysical costs. Development costs include drilling and completion costs plus additions to production facilities and equipment.

	Successor	Predecessor		
(in thousands)	**February 9, 2018 Through December 31, 2018**	**January 1, 2018 Through February 8, 2018**	**Year Ended December 31, 2017**	**Year Ended December 31, 2016**
Costs incurred during the period: (1)				
Property acquisition				
Unproved (2)	$ 54,587	$ 4,240	$ 88,378	$ 66,788
Proved (3)	16,300	327	11,704	68,478
Exploration	32,130	3,678	26,836	28,480
Development (4)	664,138	37,672	351,570	165,796
?	$ 767,155	$ 45,917	$ 478,488	$ 329,542

(1) Costs incurred in all Predecessor Periods include amounts related to non-STACK oil and gas assets, which were distributed in connection with the Business Combination. Costs incurred in 2017 include amounts related to the Weeks Island field and other assets, all of which are classified as discontinued operations.
(2) Property acquisition costs for unproved properties include the acquisition of unevaluated leasehold portion from an unaffiliated third party of approximately $22.3 million and $45.6 million for the 2018 Successor Period and the year ended December 31, 2017, respectively.
(3) Property acquisition costs for proved properties in 2016 include the transfer of Contributed Wells by our former Class B partner to us of $65.7 million.
(4) Includes asset retirement additions (revisions) of $5.6 million, $4.4 million, and $1.9 million for the Successor Period, and years ended December 31, 2017 and 2016, respectively. For the 2018 Predecessor Period, there were no material asset retirement additions (revisions).

Standardized Measure of Discounted Future Net Cash Flows

The following information utilizes reserve and production data prepared by us. Future cash inflows were calculated using the average price during the 12-month period, determined as the unweighted arithmetic average of the first-day-of-the-month, for the Successor Period, the 2018 Predecessor Period, and for the years ended December 31, 2017 and 2016. Well costs, operating costs, production and ad valorem taxes and future development costs are based on current costs with no escalation.

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The following table sets forth the components of the standardized measure of discounted future net cash flows:

?

	Successor	Predecessor		
(in thousands, except per unit data)	December 31, 2018	February 8, 2018	December 31, 2017	December 31, 2016
Future cash inflows	$ 2,446,888	$ 5,798,886	$ 5,799,753	$ 3,547,130
Future production costs	(1,214,479)	(2,556,361)	(2,617,476)	(1,811,683)
Future development costs	(23,183)	(965,780)	(1,035,481)	(709,738)
Future income taxes	(146,632)	—	—	—
Future net cash flows[1]	1,062,594	2,276,745	2,146,796	1,025,709
Discount to present value at 10 percent per annum	(348,311)	(1,096,859)	(1,040,874)	(467,101)
Standardized measure of discounted future net cash flows	$ 714,283	$ 1,179,886	$ 1,105,922	$ 558,608
Base price for crude oil, per barrel, in the above computation	$ 65.56	$ 52.89	$ 51.34	$ 42.75
Base price for gas, per Mcf, in the above computation	$ 3.10	$ 2.99	$ 2.98	$ 2.49
Realized price for NGLs, per barrel, in the above computation	$ 22.44	$ 27.48	$ 26.06	$ 15.18

Changes in Standardized Measure of Discounted Future Net Cash Flows

?

	Successor	Predecessor		
(in thousands)	February 9, 2018 Through December 31, 2018	January 1, 2018 Through February 8, 2018	Year Ended December 31, 2017	Year Ended December 31, 2016
Balance at beginning of period	$ 1,179,886	$ 1,105,922	$ 558,608	$ 629,596
Sales and transfers of oil and gas produced, net of production costs	(278,091)	(30,391)	(202,232)	(124,610)
Net changes in prices and production costs	38,963	71,334	354,900	(324,638)
Revisions of previous quantity estimates[1]	(1,120,097)	10,887	(12,106)	(35,972)
Purchases of reserves in-place	24,376	—	11,483	40,611
Sales of reserves in-place[2]	—	(4,807)	(20,423)	2,345
Current year discoveries and extensions, less related costs	684,700	—	513,012	356,631
Changes in estimated future development costs	(39,069)	491	(5,869)	849
Development costs incurred during the period	160,583	—	26,317	8,363
Accretion of discount	117,989	110,592	55,861	62,960
Net change in income taxes	(98,568)	—	—	—
Change in production rate (timing) and other	43,611	(84,142)	(173,629)	(57,527)
Net change	(465,603)	73,964	547,314	(70,988)
Balance at end of period	$ 714,283	$ 1,179,886	$ 1,105,922	$ 558,608

(1) Our revisions include approximately $250.0 million of proved undeveloped reserves that were removed at December 31, 2018 due to our subsequent determination of substantial doubt about our ability to continue as a going-concern and the impact on our ability to fund the costs associated with developing those reserves.

(2) The sale of reserves in-place during the 2018 Predecessor Period includes the sale of non-STACK properties, and in 2017 the sale of Weeks Island Field and other assets, all of which are reflected as discontinued operations in the Company's consolidated financial statements.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

Change of Independent Registered Public Accounting Firm

In July 2018, our Audit Committee approved the engagement of KPMG LLP ("KPMG") as the Company's independent registered public accounting firm for the year ending December 31, 2018. In connection with KPMG's appointment, BDO USA, LLP ("BDO") was informed in July 2018 that it was dismissed as the Company's independent registered public accounting firm. BDO was the independent auditor of the Predecessor consolidated financial statements for the fiscal years ended December 31, 2017 and 2016.

During the period from BDO's appointment through July 6, 2018, the date of BDO's replacement, there were no disagreements with BDO on any matter of accounting principles or practices, financial statement disclosure or auditing scope or procedure, which disagreement, had it not been resolved to the satisfaction of BDO, would have caused BDO to make reference thereto in its reports on the financial statements for such periods. During the same periods, there have been no "reportable events," as that term is described in Item 304(a)(1)(v) of Regulation S-K.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

On February 9, 2018, we completed the acquisition of Alta Mesa and KFM. We are currently integrating these acquisitions into our control environment. In executing this integration, we are analyzing, evaluating and, where appropriate, making changes in controls and procedures in a manner commensurate with the size, complexity and scale of operations subsequent to the acquisitions. We expect to complete the KFM integration in fiscal year 2019 and consequently excluded KFM from our assessment of internal control over financial reporting as of December 31, 2018. KFM accounted for 32% of our consolidated total assets at December 31, 2018 and12% of our consolidated operating revenue for the Successor Period.

As required by Rules 13a-15 and 15d-15 of the Exchange Act, our management, with the participation of our principal executive officer and principal financial officer, performed an evaluation of our disclosure controls and procedures. Our controls and procedures are designed to ensure that information required to be disclosed by the Company in reports it files or submits under the Exchange Act is recorded, processed, summarized, and reported within the time periods specified in the rules and forms of the SEC, and that the information required to be disclosed by the Company in reports that it files or submits under the Exchange Act is accumulated and communicated to the Company's management, including the principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure.

We have concluded that our disclosure controls and procedures were not effective as of December 31, 2018, due to the existence of material weaknesses in our internal control over financial reporting ("ICFR") described below.

In light of the material weaknesses in our ICFR, we performed extensive additional analysis and other procedures to ensure that our consolidated financial statements included in this Form 10-K were prepared in accordance with US GAAP. Following such additional analysis and procedures, our management, including our principal executive officer and principal financial officer, has concluded that our consolidated financial statements present fairly, in all material respects, our financial position, results of our operations and our cash flows for the periods presented in this Form 10-K, in conformity with GAAP.

Management's Annual Report on ICFR

Under the Exchange Act, our management is responsible for establishing and maintaining adequate ICFR. Our ICFR should be designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements in accordance with GAAP and includes those policies and procedures that:

- pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the Company's transactions and dispositions of its assets;
- provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with GAAP, and that receipts and expenditures are being made only in accordance with authorizations of management and directors; and
- provide reasonable assurance to prevent or timely detect unauthorized acquisition, use, or disposition of assets that could have a material effect on the financial statements.

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Material weakness describes a deficiency, or a combination of deficiencies, in ICFR, such that there is a reasonable possibility that a material misstatement of the annual or interim financial statements will not be prevented or detected on a timely basis.

As of December 31, 2018, management, including our principal executive officer and principal financial officer, and under the oversight of the Board of Directors, conducted an assessment of the effectiveness of our ICFR based upon the framework issued by the Committee of Sponsoring Organizations of the Treadway Commission in Internal Control-Integrated Framework (2013) (COSO 2013).We excluded KFM from our assessment of internal control over financial reporting as of December 31, 2018.KFM accounted for 32% of our consolidated total assets at December 31, 2018 and 12% of our consolidated operating revenue for the Successor Period.Using the COSO 2013 criteria, we concluded that, as of December 31, 2018, we had material weaknesses in our ICFR, as further described below:

Control Environment

We had insufficient internal resources with appropriate knowledge and expertise to design and implement, document and operate effective financial reporting processes and internal controls and our personnel did not have sufficient training on the COSO 2013 Framework and its implications on financial reporting and their related internal control roles and responsibilities. Additionally, we did not assign the proper personnel with sufficient experience to review information provided to third-party business valuation and technical accounting specialists and monitor the activities performed by them.

We did not have formal policies and procedures that defined our personnel's internal control responsibilities through performance measurement plans and goals.

Risk Assessment

We did not have an effective continuous risk assessment process to adequately identify and evaluate the risk of misstatement due to error in our recurring and nonrecurring financial reporting processes, and we did not establish effective controls to mitigate those risks.In addition, we did not adequately identify the impact of changes in our operations following the Business Combination which affected our financial reporting, and we did not establish effective internal control over both recurring and nonrecurring transactions when circumstances changed.

Information and Communication

We did not establish effective internal communication of information and related internal controls to identify and provide relevant and reliable information on a timely basis to all personnel responsible for financial reporting, and to those charged with governance to enable their effective review and oversight of financial reporting.

Monitoring Activities

We did not design, implement and maintain effective monitoring activities that span the Company to ensure that the processes and internal controls related to the five COSO 2013 Framework components and underlying principles were present and functioning. We did not have a timely process to identify all control deficiencies and we lacked sufficient cross-functional engagement to remediate the identified control deficiencies.

Control Activities

As a consequence of the ineffective control environment, risk assessment, information and communication and monitoring activities components, we did not design, implement, and maintain effective control activities over both recurring and nonrecurring transactions including the Business Combination to mitigate the risk of material misstatement in financial reporting. We did not develop written policies and procedures at a sufficient level of detail. Additionally, we did not retain the required documentation to demonstrate the consistent and timely operation of the controls at a sufficient level of precision to prevent and detect potential misstatements. In addition, we did not have the following specific control activities:

Financial Statement Close and Reporting Process

We had ineffective design and implementation and operation of controls over the financial statement close and disclosure process, including regarding assertions about the completeness, existence and accuracy of the financial information.

Information Technology (IT) Controls

IT controls over user access to the application and data base related to production volumes and the payroll application were not designed and operating effectively because user access controls did not restrict access privileges commensurate with assigned roles and responsibilities and authority or provide adequate segregation of duties. These ineffective controls impacted applications utilized in recording revenue and general and administrative expenses and other operating costs. Accordingly, automated controls and manual controls that are dependent upon the completeness and accuracy of information derived from these IT applications were also ineffective.

We did not maintain effective controls over the use of spreadsheets used to prepare our Business Combination purchase price allocation, impairment expense, operating and capital accruals, depreciation, depletion and amortization expense, determination of non-controlling interest among other accounts, such that access is restricted to appropriate personnel, that changes to data or formulas are authorized and appropriate, and that the spreadsheets are adequately reviewed by someone other than the preparer.

Management Review Controls over Complex Accounting Estimates

We did not design and implement effective management review controls over various complex accounting estimates, including controls designed to address the completeness and accuracy of data and assumptions used to measure the estimate, management's expectations and criteria for investigation of outliers and the level of precision used in the performance of the review controls.

These control deficiencies resulted in immaterial and material misstatements in the preliminary consolidated financial statements that were corrected prior to their issuance, including entries impacting oil and gas properties, exploration expense, impairment expense and amounts arising pursuant to the Business Combination. These control deficiencies create a reasonable possibility that a material misstatement to our financial statements will not be prevented or detected on a timely basis, and therefore we concluded that the deficiencies represent material weaknesses in our internal control over financial reporting, which cause our internal control over financial reporting to be ineffective as of December 31, 2018.

Our independent registered public accounting firm who audited our consolidated financial statements included in this annual report, has expressed an adverse report on the effectiveness of our internal control over financial reporting.KPMG's LLP's report is included in Item 8 of this annual report.

Company Changes in ICFR in Response to Deficiencies

IT Deficiencies

During the year, we identified ineffective user access controls over IT operating applications and databases including the application related to our financial reporting. Specifically, we did not have effective controls to ensure appropriate approval of new users and timely removal of users. Accordingly, all automated controls affecting our financial reporting and all manual controls that are dependent upon the completeness and accuracy of information derived from IT systems were also deemed ineffective. We assessed this as a material weakness.

During the quarter ended December 31, 2018, we completed remediation activities to address these deficiencies by designing and communicating written policies and procedures over administration of user access for in-scope applications. We also created and deployed policies and procedures for the core financial reporting system to improve control over authorization of user access, tailored logical access to users' job requirements and improved segregation of duties. We were able to remediate this across all IT systems affecting our financial reporting except for those IT applications affecting production volumes and payroll described above.

Except for the material weaknesses in internal control identified during the year and described above and these remediation activities related to the IT Deficiencies, there were no other changes in our ICFR during the quarter ended December 31, 2018 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Remediation

We have strengthened our ICFR for our year-end closing and reporting process and are committed to ensuring that our controls continue to mature and operate effectively. Our Board of Directors and management have prioritized the implementation of a remediation plan, taking the necessary actions to address the root causes that contributed to our material

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weaknesses and other deficiencies identified and to establish and maintain effective ICFR. The following actions and plans have been undertaken or are being undertaken:

- We now have a senior management team with seasoned experience in performing risk assessments of ICFR in complex accounting and operating environments and implementing internal control in response to identified risks, which includes our chief financial officer who has a strong background in oil and gas accounting and managing sophisticated internal control assessments, including utilization of outside advisors.

- We expect to improve the cross-functional nature of our internal control environment. We believe that embedding ICFR at all levels and across all departments will allow us to better distribute accountability for ICFR. Further, we will continue to provide ongoing GAAP and internal controls training for all our employees to embed better internal control. We will continue to assess the organization's needs in key finance and accounting positions and may retain outside resources to help supplement our employees with respect to complex accounting areas and financial reporting. This remediation effort will also include documenting roles, responsibilities and procedures and retain the appropriate evidence of the operation of control at a sufficient level of precision.

- We have engaged outside resources to assist with the design and implementation of a risk-based internal controls plan that aligns to and is measured against the COSO 2013 Framework. We plan to use outside resources to enhance the business process documentation, provide company-wide training, and help with management's self-assessment and testing of internal controls. We also plan to implement a rigorous interim testing program to better allow for remediation of identified deficiencies, as appropriate, before the year-end 2019 assessment of ICFR. We will develop a plan to address our material weaknesses related to our control environment, our risk assessment process, our control activities, information and communications and monitoring activities.

- We will evaluate and revise the risk assessment process to adequately identify, analyze and determine how we will respond to our business operations, changes to them, and the impact on financial reporting, including on ICFR. We will be more programmatic in dealing with the evolving nature of our business operations, ensuring that the risks associated with both recurring and nonrecurring transactions, including any business acquisitions, are communicated timely to those responsible for financial reporting, ICFR and those charged with governance.

- We are evaluating our IT systems and applications, including identification of shortcomings that result in over-reliance on spreadsheets and manual processes. We expect to make improvements to existing systems to automate interfaces and to enhance reporting capabilities to management, as well as to better evidence performance of key control procedures and to remediate our access controls.

- We will address our financial reporting close process activities and related controls by more clearly defining roles and responsibilities and enhancing review procedures.

- We expect to deploy enhanced management review controls over complex accounting estimates at an appropriate level of precision to reduce the risk of an undetected material misstatement. We will address the controls over the completeness and accuracy of data and assumptions used in these accounting estimates.

Item 9B. Other Information

None.

PART III

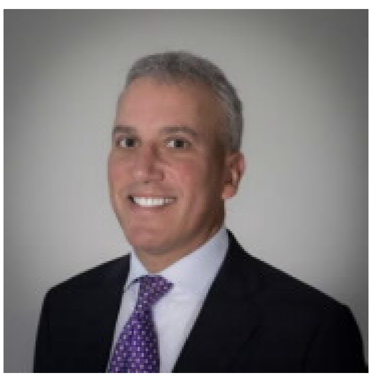
Item 10. Directors, Executive Officers and Corporate Governance

Board of Directors

We currently have nine directors. Pierre F. Lapeyre, Jr., Jeffrey H. Tepper and Diana J. Walters serve as Class II directors, with terms expiring at the 2019 Annual Meeting; James T. Hackett, Don Dimitrievich and William W. McMullenserve as Class III directors, with terms expiring at the Company's annual meeting of stockholders in 2020; and Sylvia J. Kerrigan, David M. Leuschen and Donald R. Sinclair serve as Class I directors with terms expiring at the Company's annual meeting of stockholders in 2021.Of our nine board members, four are elected by the holders of the Class A Common Stock, two are elected by the holders of the Series A Preferred Stock and three are elected by the holder of the Series B Preferred Stock.

Class II Directors

The Class II directors are listed below. If elected at the 2019 Annual Meeting, the nominees for election as Class II directors will serve on our Board for a term of three years expiring at our annual meeting of stockholders in 2022 and until their respective successors are duly elected and qualified. All nominees currently serve on our Board. In addition to the Class II nominees, Pierre F. Lapeyre, Jr.'s term as a Class II director to the Board will also expire at the 2019 Annual Meeting unless he is reelected by the affirmative vote of the holder of our Series B Preferred Stock. The holder of the Series B Preferred Stock has informed the Company that, immediately following the 2019 Annual Meeting, Mr. Lapeyre will be reappointed as a Class II director.



Jeffrey H. Tepper
Director since 2017

Age: 53

Class II Director

PRIOR BUSINESS EXPERIENCE

? Senior management and operating roles at Gleacher & Company, Inc. (1990 - 2013)

? Co-founder and President of Gleacher & Company, Inc's asset management activities (2001)

? Managing Director of and Chief Operating Officer of Gleacher NatWest Inc. (1997 - 1999)

? M&A Financial Analyst for Morgan Stanley & Co. (1987 - 1990)

CURRENT PUBLIC COMPANY BOARDS

? Director of Centennial Resource Development, Inc. (NASDAQ: CDEV)

OTHER POSITIONS

? Founder of JHT Advisors LLC (March 2017 - present)

EDUCATION

? MBA from Columbia Business School

? B.S. in Economics from The Wharton School of the University of Pennsylvania

Mr. Tepper was selected to serve on the Board due to his significant investment and financial experience.

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Diana J. Walters
Director since 2017

Age: 55

Class II Director

PRIOR BUSINESS EXPERIENCE

- President and Chief Executive Officer of Liberty Metals & Mining Holdings, LLC (2010 - 2014)
- Managing Partner of Eland Capital, LLC (2007 - 2010)

CURRENT PUBLIC COMPANY BOARDS

- Platinum Group Metals (NYSE: PLG)
- Trilogy Metals Inc. (NYSE: TMQ)
- Atmos Energy Corporation (NYSE: ATO)

OTHER POSITIONS

- Owner and sole manager of 575 Grant, LLC (2014 - present)

EDUCATION

- B.A. in Plan II Liberal Arts from University of Texas at Austin
- M.A. in Energy and Mineral Resources from University of Texas at Austin

Ms. Walters was selected to serve on the Board due to her significant investment and operating experience in the energy industry.

Pierre F. Lapeyre, Jr.
Director since 2018
Age: 56
Class II Director

PRIOR BUSINESS EXPERIENCE

- Managing Director of Goldman Sachs (1998-2000)

CURRENT PUBLIC COMPANY BOARDS

- Non-executive board member of Riverstone Energy Limited (LSE: REL)

OTHER POSITIONS

- Founder of Riverstone and Senior Managing Director (2000-present)
- Non-executive board member of Centennial Resource Development, Inc.
- Director of boards or equivalent bodies of a number of private Riverstone portfolio companies and their affiliates

EDUCATION

- MBA from the University of North Carolina at Chapel Hill
- B.S. in Finance and Economics from the University of Kentucky

Mr. Lapeyre was selected to serve on the Board due to his extensive mergers and acquisitions, financing and investing experience in the energy and power industry.

Class I and Class III Directors

Our Class I and Class III directors are listed below.

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James T. Hackett

Chairman and Interim CEO (since December 2018)

Age: 65

Class III Director

PRIOR BUSINESS EXPERIENCE

- Chief Operating Officer—Midstream (February - April 2018) and the CEO —Midstream
- Senior Advisor and former Partner with Riverstone Holdings LLC, a private energy investment firm (2013 - 2019)
- Chairman of the Board (2006 - 2013) and Chief Executive Officer (2003 - 2012) of Anadarko Petroleum Corporation
- Chairman of the Board of the Federal Reserve Bank of Dallas (2004 - 2006)
- President and Chief Operating Officer of Devon Energy Corporation (2003)
- Chairman, President, and Chief Executive Officer of Ocean Energy and its predecessor Company, Seagull Energy (1998 - 2003)
- President of Energy Services Group at Duke Energy Corporation and Executive VP at PanEnergy Corp. (1996 - 1998)

CURRENT PUBLIC COMPANY BOARDS

- Director of Fluor Corporation (NYSE: FLR)
- Director of National Oilwell Varco, Inc. (NYSE: NOV)
- Director of Enterprise Products Holdings, LLC (NYSE: EPD)

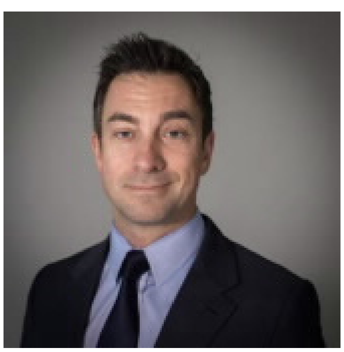
OTHER POSITIONS

- Director of Talen Energy Corporation
- Member of Rice University and Baylor College of Medicine Trustees (and former Chairman of the latter)
- Faculty member at University of Texas at Austin and Rice University

EDUCATION

- Bachelor of Science, University of Illinois
- MBA and MTS degrees from Harvard University

Mr. Hackett was selected to serve on the Board due to his significant leadership experience and his extensive experience in the energy industry.



Donald R. Dimitrievich

PRIOR BUSINESS EXPERIENCE

- Skadden, Arps, Slate, Meagher & Flom LLP (1998 - 2004)
- Managing Director of Citi Credit Opportunities

OTHER POSITIONS

- Managing Director at HPS Investment Partners (2012-present)
- Director of Blue Ridge Mountain Resources, Inc.
- Director Expro International Group Holdings Ltd.
- Director Glacier Oil & Gas Corp.
- Director Marquis Resources, LLC
- Director Upstream Exploration Holdings LLC.

Director since 2018

Age: 47

Class III Director

EDUCATION

- ? Law Degree magna cum laude, McGill University in Montreal, Canada
- ? Chemical Engineering degree, Queen’s University in Kingston, Canada

Mr. Dimitrievich was selected to serve on the Board due to his significant mergers and acquisitions, financing and investing experience in the energy industry.

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William W. McMullen
Director since 2018
Age: 34
Class III Director

PRIOR BUSINESS EXPERIENCE

- Manager of Bayou City Energy Partners ("BCEP") (April 2014-present)
- Vice President at White Deer Energy (June 2012-October 2014)
- Associate at Denham Capital (June 2010-June 2012)
- Analyst in UBS Investment Bank's Global Energy group (July 2008-June 2010)

OTHER POSITIONS

- Founder and Managing Partner of Bayou City Energy (January 2015-present)

EDUCATION

- Bachelor's degree in Economics, with Honors, from Harvard University.

Mr. McMullen was selected to serve on the Board due to his broad knowledge of, and experience with, oil and gas investments.

Sylvia J. Kerrigan
Director since 2018

Age: 54
Class I Director

PRIOR BUSINESS EXPERIENCE

- Executive Vice President, General Counsel and Secretary of Marathon Oil Corporation (2012 - 2017)
- Chief Public Policy Officer of Marathon (2014 - 2017)
- Chief Compliance Officer of Marathon (2013- 2017)
- Vice President, General Counsel and Secretary of Marathon (2009 - 2012)
- Head of Information Governance of Marathon (2009-2017)
- United Nations Security Council's Commission d'Indemnisation in Geneva, Switzerland serving as their senior legal officer (2000 - 2001)

CURRENT PUBLIC COMPANY BOARDS

- Director of Team, Inc. (NYSE: TISI), where she sits on the Audit Committee and Corporate Governance and Nominations Committee

OTHER POSITIONS

- Director for Nine Point Energy, where she is the Chair of the Audit Committee and sits on the Compensation Committee.
- Board of Trustees for Southwestern University
- Executive Director and Executive Council of the Kay Bailey Hutchison Center for Energy, Law and Business at the University of Texas in Austin

EDUCATION

- J.D. from the University of Texas at Austin School of Law
- B.A. from Southwestern University, concentrating in philosophy, political economy and English

Ms. Kerrigan was selected to serve on the Board due to her experience as chief legal officer, chief public policy officer and chief compliance officer of a public corporation, and her extensive merger and acquisition, risk management and corporate governance expertise.

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David M. Leuschen
Director since 2018
Age: 68
Class I Director

PRIOR BUSINESS EXPERIENCE

- Partner and Managing Director of Goldman Sachs (1986 - 2000)
- Founder and head of the Goldman Sachs Global Energy and Power Group (1985 - 2000)

CURRENT PUBLIC COMPANY BOARDS

- Non-executive board member of Riverstone Energy Limited (LSE: REL)
- Non-executive board member of Centennial Resource Development, Inc. (NASDAQ: CDEV)

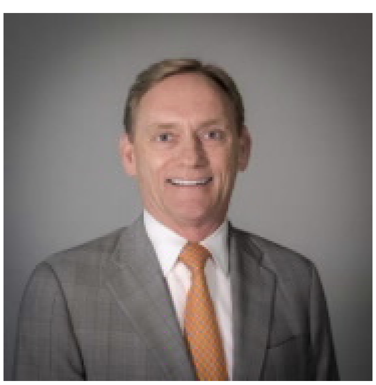
OTHER POSITIONS

- Founder of Riverstone and Senior Managing Director (2000-present)
- Director of boards or equivalent bodies of a number of private Riverstone portfolio companies and their affiliates

EDUCATION

- MBA from Dartmouth's Amos Tuck School of Business
- A.B. degree from Dartmouth College

In 2007, Mr. Leuschen, along with Riverstone and The Carlyle Group ("Carlyle"), became the subject of an industry-wide inquiry by the Office of the Attorney General of the State of New York (the "Attorney General") relating to the use of placement agents in connection with investments by the New York State Common Retirement Fund ("NYCRF") in certain funds, including funds that were jointly developed by Riverstone and Carlyle. In June 2009, Riverstone entered into an Assurance of Discontinuance with the Attorney General to resolve the matter and agreed to make a restitution payment of $30 million to the New York State Office of the Attorney General for the benefit of NYCRF. Mr. Leuschen also entered into an Assurance of Discontinuance with the Attorney General in December 2009 and agreed that Riverstone and/or Mr. Leuschen would make a restitution payment of $20 million to the New York State Office of the Attorney General for the benefit of NYCRF. Mr. Leuschen was selected to serve on the Board due to his extensive mergers and acquisitions, financing and investing experience in the energy and power industry.



Donald R. Sinclair

Director since 2018
Age: 61
Class I Director

PRIOR BUSINESS EXPERIENCE

- Senior Advisor to Anadarko Petroleum Corporation (NYSE: APC) (2017-2018)
- Director, President and Chief Executive Officer of WES GP (2009 to 2017)
- Vice President and Senior Vice President of Anadarko Petroleum Corporation (2010 to 2016)
- Co-founder, President and Chief Executive Officer of Ceritas Energy, LLC (2003 to 2009)
- Energy industry consulting and management of personal business interests (1998 to 2003)
- President of Duke Energy Trading and Marketing LLC (1997 to 1998)
- Senior Vice President of Tenneco Energy, a unit of Tenneco Inc., and as President of Tenneco Energy Resources Corporation (May 1995-December 1995)
- Senior Vice President and Chief Risk Officer of Dynegy Inc. (formerly NGC Corporation) (January 1993-February 1994)

OTHER POSITIONS

- Chairman of the Board of Directors and President of WTX Pumping Services LLC
- Director of Lucid Energy Group II, LLC

- Director of Ascent Resources, LLC

EDUCATION

- Bachelor of Business Administration degree from Texas Tech University

Mr. Sinclair was selected to serve on the Board due to his significant leadership experience and his extensive investment experience in the oil and gas industry.

Preferred Stock Board Appointments

On December 20, 2018, AM Equity Holdings, LP redeemed its share of Series A Preferred Stock.As a result, each of Bayou City Energy Management, LLC ("Bayou City") and HPS Investment Partners, LLC ("HPS") ownthe only outstanding shares of our Series A Preferred Stock. For so long as the Series A Preferred Stock remains outstanding, the holders of the Series A Preferred Stock are entitled to nominate and elect directors to our Board for a period of five years following the closing of the Business Combination, based on their and their affiliates' beneficial ownership of Class A Common Stock as follows:

Holder / Beneficial Ownership and Other Requirements	Designation Right
Bayou City and its affiliates	
•at least 10%	one director who must be independent for purposes of the listing rules of NASDAQ (unless the director to be nominated is William W. McMullen who need not be independent)
HPS and its affiliates	
•at least 10%	one director who must be independent for purposes of the listing rules of NASDAQ

Mr. McMullen serves as a Class III director on the Board on behalf of Bayou City, and Mr. Dimitrievich serves as a Class III director on the Board on behalf of HPS.

The Riverstone Contributor owns the only outstanding share of our Series B Preferred Stock. For so long as the Series B Preferred Stock remains outstanding, the holder of the Series B Preferred Stock is entitled to nominate and elect directors to our Board for a period of five years following the Closing based on its and its affiliates' beneficial ownership of Class A Common Stock as follows:

Holder / Beneficial Ownership and Other Requirements	Designation Right
Riverstone Contributor and its affiliates	
•at least 15%	three directors (one of whom will be the Chairman of the Board)
•less than 15% but at least 10%	two directors (one of whom will be the Chairman of the Board)
•less than 10% but at least 5%	one director (who may be the Chairman of the Board if such person is James Hackett)

Mr. Leuschen serves as a Class I director, Mr. Lapeyre serves as a Class II director and Mr. Hackett serves as a Class III director on the Board on behalf of the Riverstone Contributor.

Board Leadership Structure

Currently, James T. Hackett serves as our Executive Chairman of the Board and our Interim Chief Executive Officer. We have no policy with respect to the separation of the offices of Chairman and Chief Executive Officer. The Board believes that it is important to retain its flexibility to allocate the responsibilities of the offices of the Chairman and Chief Executive Officer in any way that is in the best interests of the Company at a given point in time.

Board Role in Risk Oversight

The Board oversees the Company's management and, with the assistance of management, is actively involved in oversight of risks that could affect the Company. During the course of each year, the Board engages in the oversight of risk in various ways, including by (i) reviewing and approving management's operating plans and considering any risks that could affect operating results, (ii) reviewing the structure and operation of our various departments and functions, (iii) in connection with the review and approval of particular transactions and initiatives, reviewing related risk analyses and mitigation plans and (iv) facilitating appropriate coordination among the Board committees as set forth below.

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The Board has also delegated certain risk oversight responsibility to committees of the Board as follows: (i) the audit committee of the Board (the "Audit Committee") oversees the Company's guidelines and policies governing the process by which senior management assess and manage the Company's exposure to risk, as well as the Company's major financial risk exposures and the steps management has taken to monitor and control those exposures; (ii) the compensation committee of the Board (the "Compensation Committee") oversees risk related to senior executive and other compensation; and (iii) the nominating and corporate governance committee of the Board (the "Nominating and Corporate Governance Committee") oversees risk related to corporate governance.

Risk Assessment Related to Our Compensation Structure

Our Board and our Compensation Committee take risk into account when making compensation decisions and has concluded that the executive compensation program as it is currently structured does not encourage excessive risk or unnecessary risk-taking.

The Compensation Committee is comprised solely of independent directors and is principally responsible for establishing, overseeing and administering our compensation plans and policies for our executive officers, including our equity incentive plans.The Compensation Committee is also responsible for overseeing risks related to our compensation programs and practices.The Compensation Committee has assessed the risk associated with our compensation policies and practices for our employees and determined that the risks associated with such policies and practices are not reasonably likely to have a material adverse effect on us. The Compensation Committee utilizes compensation practices that it believes discourage our employees from excessive risk-taking that could be reasonably likely to have a materially adverse effect on us, including the following:

- The base salary component of compensation does not encourage risk-taking because it is a fixed amount.
- A combination of both short-term and long-term elements of executive compensation are included.
- The design and mix of our equity awards are intended to mitigate risk. The time-based vesting structure discourages short-term risk-taking at the expense of long-term stockholder value and a performance-based award can be earned only upon the achievement of challenging corporate goals selected to motivate executives to achieve our corporate objectives and enhance stockholder value.

Assuming achievement of a threshold level of performance, payouts under our annual cash incentive compensation program result in some compensation at levels below full target achievement, rather than an "all-or-nothing" approach, which could encourage excessive risk-taking.

Committees of the Board

The Board had three standing committees during the fiscal year 2018: the Audit Committee, the Compensation Committee and the Nominating and Corporate Governance Committee, which was established by the Board after the closing of the Business Combination in February 2018.Each of the committees reports to the Board as it deems appropriate and as the Board may request. The composition, duties and responsibilities of these committees are set forth below.

In addition, from time to time and as necessary to address specific issues, other committees may be established under the direction of our Board.

Audit Committee

The principal functions of the Company's Audit Committee are detailed in the Company's Audit Committee Charter, which is available on the Company's website at www.altamesa.net, and include, but are not limited to:

- being responsible for the appointment, compensation, retention and oversight of the work of the independent auditors and any other independent registered public accounting firm engaged by the Company;
- pre-approving all audit and permitted non-audit services to be provided by the independent auditors or any other registered public accounting firm engaged by the Company;
- reviewing the performance of the independent auditors and making decisions regarding the replacement or termination of the independent auditors;
- evaluating the independence of the independent auditors by, among other things, reviewing and discussing with the independent auditors all relationships the auditors have with the Company; setting clear hiring policies for the Company for employees or former employees of the independent auditors; and monitoring compliance by the independent auditors with the auditor partner rotation requirements contained in applicable laws, rules and regulations;
- reviewing and discussing with the independent auditors their annual audit plan and reviewing with management and the independent auditors' information which is required to be reported by the independent auditor;

- reviewing, among other things, the adequacy and effectiveness of the Company's accounting and internal control policies and procedures through inquiry and discussions with the Company's independent auditors and management;
- reviewing and approving any related party transaction required to be disclosed pursuant to Item 404 of Regulation S-K promulgated by the SEC prior to us entering into such transaction; and
- reviewing and discussing with management, the independent auditors and our legal advisors, as appropriate, any legal, regulatory or compliance matters as such matters may arise.

Under the NASDAQ listing standards and applicable SEC rules, the Company is required to have at least three members of the Audit Committee, all of whom must be independent. Our Audit Committee consists of Mr. Jeffrey H. Tepper and Mses. Sylvia J. Kerrigan and Diana J. Walters, with Ms. Diana J. Walters serving as the Chair. Ms. Kerrigan replaced Mr. William D. Gutermuth upon election to our Board on June 18, 2018.We believe that Mr. Tepper and Mses. Kerrigan and Walters qualify as independent directors according to the rules and regulations of the SEC with respect to audit committee membership and that Mr. Gutermuth also met such independence requirements during his tenure on the Audit Committee. We also believe that Jeffrey H. Tepper and Diana J. Walters each qualifies as our "audit committee financial expert," as such term is defined in Item 401(h) of Regulation S-K.

During the fiscal year ended December 31, 2018, the Audit Committee held 8 meetings and took action by written consent 3 times.

Compensation Committee

The principal functions of the Company's Compensation Committee are detailed in the Company's Compensation Committee Charter, which is available on the Company's website at www.altamesa.net, and include, but are not limited to:

- reviewing at least annually the goals and objectives of the Company's executive compensation plans;
- reviewing at least annually the Company's executive compensation plans;
- evaluating annually the performance of the Company's Chief Executive Officer, and determining and approving the Chief Executive Officer's compensation level based on this evaluation;
- evaluating annually the performance of the other executive officers of the Company, and determining and approving the compensation of such other executive officers;
- evaluating annually the appropriate level of compensation for Board and committee service by non-employee directors;
- reviewing and discussing with management the Company's Compensation Discussion & Analysis disclosure, and recommending to the Board that the Compensation Discussion & Analysis disclosure be included in the Company's annual proxy statement or annual report;
- preparing the Compensation Committee Report for inclusion in the Company's proxy statement and annual report;
- reviewing at least annually the goals and objectives of the Company's general compensation plans and other employee benefit plans, including incentive-compensation and equity-based plans;
- reviewing at least annually the Company's general compensation plans and other employee benefit plans, including incentive-compensation and equity-based plans; and
- reviewing all equity-compensation plans to be submitted for stockholder approval under the NASDAQ listing standards, and reviewing and approving all equity-compensation plans that are exempt from such stockholder approval requirement.

Under the NASDAQ listing standards, the Company is required to have a Compensation Committee, all of whom must be independent. Until July 1, 2019, our Compensation Committee consisted of Messrs. Donald R. Sinclair and Jeffrey H. Tepper and Ms. Diana J. Walters, with Mr. Sinclair serving as the Chair. Mr. Sinclair replaced Mr. William D. Gutermuth upon closing of the Business Combination.Effective July 1, 2019, Ms. Sylvia J. Kerrigan replaced Ms. Walters on the Compensation Committee. We believe that Messrs. Sinclair and Tepper and Mses. Walters and Kerrigan qualify as independent directors according to the rules and regulations of the NASDAQ with respect to compensation committee membership, and that Mr. Gutermuth also met such independence requirements during his tenure on the Compensation Committee.

During the fiscal year ended December 31, 2018, the Compensation Committee held 1 meeting and took action by written consent 6 times.

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Nominating and Corporate Governance Committee

The Nominating and Corporate Governance Committee was established by the Board following the closing of the Business Combination. The principal functions of the Company's Nominating and Corporate Governance Committee are detailed in the Company's Nominating and Corporate Governance Committee Charter, which is available on the Company's website at www.altamesa.net, and include, but are not limited to:

- identifying individuals qualified to become members of the Board and ensuring that the Board has the requisite expertise and that its membership consists of persons with sufficiently diverse and independent backgrounds;
- recommending director nominees for election to the Board at the next annual meeting of stockholders;
- reviewing the Board committee structure annually and recommending directors to serve as members of each committee;
- overseeing the annual self-evaluations of the Board and management;
- making recommendations to the Board regarding governance matters;
- reporting regularly to the Board regarding the activities of the Nominating and Corporate Governance Committee;
- performing at least annually an evaluation of the performance of the Nominating and Corporate Governance Committee; and
- reviewing and reassessing periodically the Nominating and Corporate Governance Committee Charter.

The Nominating and Corporate Governance Committee also develops and recommends to the Board corporate governance principles and practices and assists in implementing them, including conducting a regular review of our corporate governance principles and practices. The Nominating and Corporate Governance Committee oversees the annual performance evaluation of the Board and the committees of the Board and makes a report to the Board on succession planning.

Our Nominating and Corporate Governance Committee consists of Messrs. Donald R. Dimitrievich, Donald R. Sinclair, Jeffrey H. Tepper and Ms. Diana J. Walters, with Mr. Tepper serving as the Chair.

During the fiscal year ended December 31, 2018, the Nominating and Corporate Governance Committee held 1 meeting and took action by written consent 3 times.

Executive Officers

See *Executive Officers* under Item 1 of this Annual Report for information about our executive officers.

Code of Business Conduct and Ethics

We have adopted a Code of Business Conduct and Ethics applicable to our directors, officers and employees and have posted a copy on our website www.altamesa.net. In addition, a copy of the Code of Business Conduct and Ethics will be provided without charge upon request directed to Alta Mesa Resources, Inc., 15021 Katy Freeway, Suite 400, Houston, Texas 77094, Attention: Secretary. We intend to disclose any amendments to or waivers of certain provisions of our Code of Business Conduct and Ethics in a Current Report on Form 8-K.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act requires our officers and directors, and persons who own, or are part of a group that owns, more than 10% of a registered class of our equity securities, to file reports of ownership and changes in ownership with the SEC. Officers, directors and greater than 10% stockholders are required by regulation of the SEC to furnish us with copies of all Section 16(a) forms they file.

Based solely on our review of Forms 3, 4 and 5 and amendments thereto and other information obtained from our directors and officers and certain 10% stockholders or otherwise available to us, we believe that no director, officer or beneficial owners of more than 10% of our total outstanding shares of Common Stock failed to file the reports required by Section 16(a) of the Exchange Act on a timely basis during the fiscal year ended December 31, 2018.

Item 11. Executive Compensation

Compensation Committee Report

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The Compensation Committee has reviewed and discussed with management the Company's Compensation Discussion and Analysis for 2018. Based on that review and discussion, the Compensation Committee has recommended to the Board that the Compensation Discussion and Analysis be included in the Company's Proxy Statement and this Annual Report on Form 10-K for the fiscal year ended December 31, 2018.

Compensation Committee

Donald R. Sinclair (Chair)
Sylvia J. Kerrigan
Jeffrey H. Tepper

Compensation Committee Interlocks and Insider Participation

During the fiscal year ended December 31, 2018, no officer or employee served as a member of our Compensation Committee. None of our executive officers serve as a member of the board of directors or compensation committee of any entity that has one or more executive officers serving on our Board or Compensation Committee.

Compensation Discussion and Analysis

On February 9, 2018, we consummated the acquisition of (i) all of the limited partnership interest in Alta Mesa Holdings, LP, (ii) 100% of the economic interests and 90% of the voting interests in Alta Mesa Holdings GP, LLC, the sole general partner of Alta Mesa Holdings, LP and (iii) all of the membership interests in Kingfisher Midstream, LLC, which we collectively refer to as the "Business Combination."None of our officers received any cash compensation from us for services rendered to us for the year ended December 31, 2017, nor did we grant any equity awards to any of our officers for 2017.

The following Compensation Discussion and Analysis describes in detail the compensation paid to the named executive officers ("NEOs") listed in the Summary Compensation Table. It is designed to provide stockholders with an understanding of our compensation principles and practices and insight into our decision-making process as it relates to the compensation of our NEOs.

For 2018, our NEOs were:

Name	**Title**
James T. Hackett	Executive Chairman of the Board and Interim Chief Executive Officer
Michael A. McCabe[1]	Former Vice President and Chief Financial Officer
Craig W. Collins[2]	Former Vice President and Chief Operating Officer-Midstream
Kimberly O. Warnica	Executive Vice President, General Counsel, Chief Compliance Officer and Secretary[5]
Ronald J. Smith[3]	Former Vice President and Chief Accounting Officer
Harlan H. Chappelle[4]	Former President and Chief Executive Officer
Michael E. Ellis[4]	Former Vice President and Chief Operating Officer-Upstream
Homer "Gene" Cole[4]	Former Vice President and Chief Technical Officer

(1) Mr. McCabe retired as of March 29, 2019.
(2) Mr. Collins' last day of employment was April 3, 2019.
(3) Mr. Smith's last day of employment was July 19, 2019.
(4) Messrs. Chappelle, Ellis and Cole's resigned effective December 26, 2018.
(5) Effective June 18, 2019, Ms. Warnica's title changed from Vice President, General Counsel, Chief Compliance Officer and Secretary to Executive Vice President, General Counsel, Chief Compliance Officer and Secretary.

Executive Summary

2018 was a year of significant transition and transformation for the Company.In February, the Company completed the Business Combination thereby creating a newly integrated and public upstream and midstream company focused on the Sooner

Trend Anadarko Basin Canadian and Kingfisher County ("STACK"). In conjunction with the Business Combination, there was a significant infusion of new capital to fund the growth and development of the assets. The focus of the capital deployed in 2018 was the pursuit of significant near-term growth of the upstream and midstream businesses. These growth initiatives included increasing the rig count from four to nine rigs at the peak in 2018, completing a 200 MMcfd expansion of the gas processing plant, the overall expansion of the asset footprint through the acquisition of additional acreage in Kingfisher and Major Counties, and the construction of pipeline infrastructure into Major County.

In setting quantitative goals for the Company, these growth plans were used to underpin the specific upstream and midstream operating and financial targets that drove compensation targets. Over the course of 2018, the pace of growth achieved and the cost to achieve that growth fell significantly below the expectations the Company had at the time of the Business Combination. As a result of not performing in line with the quantitative performance metrics set out, the compensation payout realized by executives and the entire employee base for 2018 was significantly below the target compensation levels.

While the growth plans and capital efficiency targets of the Company were not met, the Company was successful in integrating the upstream and midstream operating platforms over the course of the year. Additionally, the Company took significant steps forward in understanding how to optimize development of the upstream resource. The Company intends to leverage successful integration and the enhanced knowledge base around the optimal upstream development to inform the strategy and execution going forward.

Performance Metrics

Our executive compensation program is closely tied to both individual and Company performance as well as direct alignment with our stockholders. Our annual incentive compensation plan delivers payments that are directly correlated with strategic operational and financial performance achieved and is designed so that Company performance significantly impacts the realized pay of our NEOs. Additionally, our long-term incentives align with stockholder value creation and the use of options provides a meaningful stake in the Company stock performance. In combination, the realizable compensation reflects near-term financial and operating successes and long-term stock performance. As demonstrated in the chart below, the Company’s performance has impacted the realized pay of each of our NEOs and compensation in 2018 was delivered in line with our performance outcomes. Values for the table were determined with the following inputs:

- For Target Compensation:
    - ? Target Base Salary
    - ? Target Non-Equity Incentive Plan Compensation
    - ? Equity fair grant date values for restricted stock awards, performance based restricted stock units and option awards as reported in the Summary Compensation Table and as further described in footnote (3) to the Summary Compensation Table.

- For Realized Pay:
    - ? 2018 Base Salary Paid
    - ? 2018 Non-Equity Plan Compensation Paid (average of 10% of Target): Based on the Company’s performance results for the year ended December 31, 2018, the weighted average of bonuses received by the NEOs was approximately 10% of their target bonuses, with each of Messrs. Hackett, Chappelle, McCabe, Ellis and Cole receiving no bonus for 2018.
    - ? Vested Equity as of December 31, 2018
        - ? Restricted Stock Awards: Only Mr. Cole realized income from restricted stock awards which awards vested as a result of his employment contract upon his separation. As of December 31, 2018, a total of 501,314 restricted stock awards remained unvested.
        - ? Performance Based Restricted Stock Units: Based on the Company’s performance results for the period from February 9, 2018 through December 31, 2018, the NEOs who remained employed at year-end did not earn any of the 2018 performance units. Accordingly, other than Messrs. Chappelle, Ellis and Cole, who had employment contracts that provided for vesting and payout at target levels upon their separation, there was no payout associated with the 2018 performance based restricted stock units.
        - ? Stock Option Awards: Stock options owned by Messrs. Chappelle, Ellis and Cole vested pursuant to their employment contracts upon their separation, all of which are significantly out-of-the-money. As of December 31, 2018, a total of 1,237,801 options remained unvested, all of which are significantly out-of-the-money.

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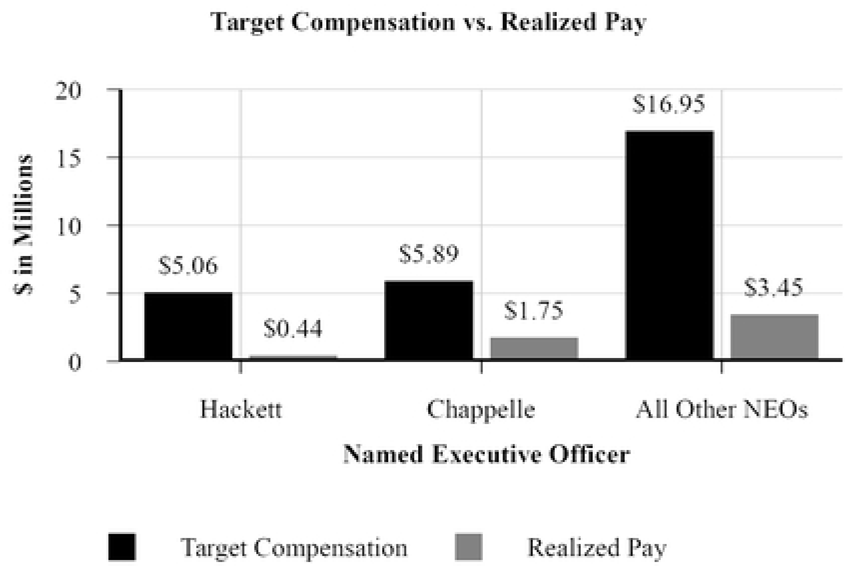
? Severance benefits in the amount of $3,775,000, $1,545,000 and $1,340,250 have been excluded for Messrs. Chappelle, Ellis and Cole, respectively.



Leadership Transitions

Our Board, together with management, successfully added two new key executive leadership positions in 2018.Craig W. Collins joined the Company as Vice President and Chief Operating Officer-Midstream, and Kimberly O. Warnica joined the Company as Vice President, General Counsel, Chief Compliance Officer and Secretary, both in April 2018.

Messrs. Chappelle, Ellis and Cole were given an opportunity to resign from the Company, which was effective December 26, 2018, Mr. McCabe was given an opportunity to retire from the Company, which was effective March 29, 2019, the Company and Mr. Collins came to a mutual understanding with respect to Mr. Collins' separation from the Company, which was effective on April 3, 2019, and the Company and Mr. Smith came to a mutual understanding with respect to Mr. Smith's separation from the Company, which was effective July 19, 2019.See “Executive Compensation-Potential Payments Upon Termination or Change in Control-Post-Termination Compensation” for a description of certain benefits to which these executives were entitled. The payments made to these individuals were based on the Company’s obligations under their respective employment agreements. In the case of Messrs. Chappelle, Ellis, Cole, McCabe and Smith, these agreements were entered into in connection with the Business Combination and were intended to ensure the retention and focus of the management team during the early stages of the Company’s growth.

As a result of these departures, four new executives joined the Company in January 2019: Randy L. Limbacher, as Interim President; John C. Regan, as Vice President and Chief Financial Officer; John H. Campbell, Jr., as Interim Chief Operating Officer-Upstream, and Mark P. Castiglione, as Chief of Staff to the President. Effective June 18, 2019, Ms. Warnica's title was changed to Executive Vice President, General Counsel, Chief Compliance Officer and Secretary, Mr. Regan's title was changed to Executive Vice President, Chief Financial Officer and Assistant Secretary, Mr. Campbell's title was changed to Interim Executive Vice President and Chief Operating Officer and Mr. Castiglione's title was changed to Interim Executive Vice President-Strategy and Corporate Development. For information regarding the 2019 compensation arrangements with respect to Messrs. Limbacher, Campbell and Castiglione and Mr. Regan, see our Forms 8-K filed on December 27, 2018 and January 7, 2019, respectively. For information on our 2019 incentive compensation program, see our Form 8-K filed on March 28, 2019.None of our named executive officers received raises to their base salaries for 2019.

Role of Management and Compensation Consultant

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For 2018, the Compensation Committee directly engaged Pearl Meyer & Partners, LLC as its independent compensation consultant to advise the Compensation Committee on executive compensation matters. Pearl Meyer provides the Compensation Committee with information on industry trends, market practices and legislative issues. Pearl Meyer provides no other services to the Company or our executive officers, and the Compensation Committee has the right to terminate the services of Pearl Meyer and appoint a new compensation consultant at any time. Additionally, Pearl Meyer has provided the Compensation Committee with certification of its independence as set out under the rules of the Securities Exchange Act of 1934, as amended, and regulations promulgated under Dodd Frank.

Pearl Meyer interacts with several of our officers and employees as necessary. In addition, Pearl Meyer may seek input and feedback from members of our management regarding its work product prior to presentation to the Compensation Committee to confirm that information is accurate or address other issues. The Compensation Committee periodically meets independently with Pearl Meyer without management's presence. We believe that Pearl Meyer provides an independent perspective to the Compensation Committee.

The Compensation Committee seeks significant input from the CEO on compensation decisions and performance appraisals for all executive officers other than himself. However, all final compensation decisions for our executive officers are made by the Board after taking into consideration the recommendations of the Compensation Committee. The CEO does not provide recommendations or participate in Compensation Committee discussions concerning his own compensation.

Benchmark Peer Group

The Compensation Committee, with assistance from Pearl Meyer, its independent compensation consultant, approved a compensation peer group in 2018, which consisted of:

Approach Resources, Inc.	EOG Resources, Inc.	Pioneer Natural Resources Company
Concho Resources Inc.	Marathon Oil Corporation	Range Resources Corporation
Continental Resources, Inc.	Midstates Petroleum Company, Inc.	RSP Permian, Inc.
Diamondback Energy, Inc.	Newfield Exploration Company	Whiting Petroleum Corporation
Energen Corporation	Noble Energy, Inc.	

For fiscal year 2018, as part of its annual review, the Compensation Committee determined that the peer group should be comprised of a combination of producers in the Company's operating areas plus those of comparable size and revenue projections through 2018.These estimates were based upon an aggressive growth model. Using the peer group benchmarks, the Compensation Committee targeted the first quartile for fixed pay and the median of the 2018 peer group for variable pay, based upon achievement of the applicable performance metrics. The data compiled on the selected peer companies covered enterprise value, market capitalization, mix or characteristics of reserves and other factors such as operating footprint. Due to the strong correlation of revenue to executive pay, the basis for the peer group selection was such that the Company would fit into the median revenue levels (25^{th} to 75^{th} percentile) by year-end based on the projected growth.

Early in 2019, with the backdrop of disappointing financial performance and near-term projections, Pearl Meyer was asked to re-assess the peer group for 2019. Pearl Meyer conducted a study analyzing peers of peers as well as peers from proxy advisory firms and solicited input from Company leadership, which resulted in a list of potential peer companies. This list was narrowed after considering several factors such as type of operators, areas of operation and more appropriate direct comparability of the median revenue of the new group to that of the Company. As a result, using the Company’s projected revenues, the Company falls above the median for the new peer group in terms of revenue, market capitalization and enterprise value and at the top of the group for asset values. The Company believes this new peer group is appropriate for establishing 2019 compensation plans as the Company establishes the new strategy.

Approach Resources, Inc.	Comstock Resources, Inc.	Midstates Petroleum Company, Inc.
Bonanza Creek Energy, Inc.	Eclipse Resources Corporation	Penn Virginia Corporation
Callon Petroleum Company	Halcon Resources Corporation	SandRidge Energy, Inc.
Carrizo Oil & Gas, Inc.	Laredo Petroleum, Inc.	SilverBow Resources, Inc.
Chaparral Energy, Inc.		

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Compensation Governance and Best Practices

The Compensation Committee periodically evaluates market best practices in executive compensation and adjusts our compensation program as necessary to ensure it continues to provide balanced incentives, while managing compensation risks appropriately in the context of our business objectives. Our program has the following features that we believe comprise best practices:

WHAT WE DO
☑ Emphasize at-risk compensation designed to link pay to performance
☑ Maintain robust stock ownership requirements for executive officers and directors
☑ Engage an independent compensation consultant to advise the Compensation Committee
☑ Subject performance-based compensation to a clawback policy
☑ Minimize use of perquisites

WHAT WE DON'T DO
☒ Allow pledging of Company securities, including margin accounts
☒ Permit short sales or derivative transactions in Company securities, including hedges
☒ Provide single trigger vesting of equity and cash awards
☒ Reward executives for excessive, unnecessary or inappropriate risk-taking

Compensation Philosophy

Our executive compensation program is intended to motivate our executive officers to achieve strong financial and operating results.In addition, our program is designed to achieve the following objectives:

- **Pay for performance**. Our program is designed to reward executives for their performance and motivate them to perform at a high level. Cash bonuses, based on annual Company as well as individual performance, coupled with our equity awards that generally vest over a three-year period, balance short-term and long-term Company objectives.A substantial portion of our NEO's long-term incentive awards is comprised of performance units.

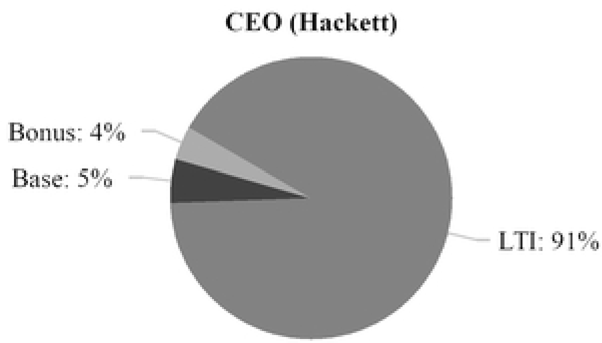
- **Encourage long-term stockholder value creation**. Equity awards and robust stock ownership requirements align executives' interests with our stockholders.

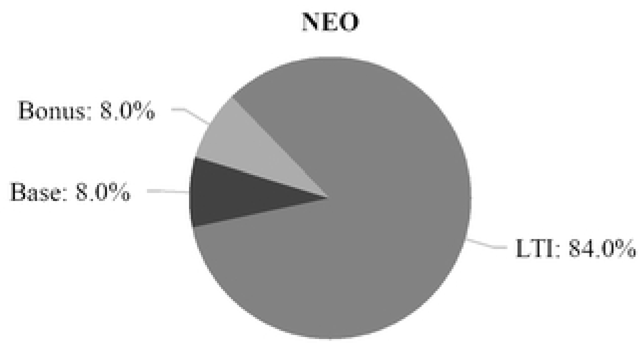
- **Pay competitively**. Attract and retain highly qualified executive officers by providing reasonable total compensation levels competitive with that of executives holding comparable positions in similarly situated organizations.

Elements of Our Compensation Program

To accomplish our objectives, our compensation program is comprised primarily of the following elements: base salary, cash bonus, long-term incentives and benefits. By design, a significant portion of our NEOs' overall 2018 compensation, including annual cash bonuses and long-term incentive awards, is "performance-based," and the opportunity to earn value is largely dependent on both Company and individual performance. The Compensation Committee determines a total compensation opportunity for each executive officer based on a review of competitive market data, utilization of third party industry sources and an independent compensation consultant, a review of the Company's compensation philosophy and the Compensation Committee's subjective judgment. The Compensation Committee does not set fixed percentages for each element of compensation, so the mix may change over time as the competitive market moves, governance standards evolve or our business needs change.

The following pie charts show the 2018 pay mix of total target direct compensation components for our interim CEO and other NEOs, respectively. Approximately 95% of our interim CEO's total target direct compensation for 2018 was influenced by Company performance.





The Compensation Committee determined 2018 base salaries, annual incentive cash bonus opportunities and long-term incentive ("LTI") awards in February 2018. The Compensation Committee determined the amount of 2018 annual cash bonuses in February 2019, after preliminary 2018 business results were known.

Base Salary

Base salaries are intended to provide a level of stability and certainty each year with respect to compensation. We pay base salary to recognize and reward overall responsibilities, experience and established skills. In setting base salary, the Compensation Committee compares each NEO's current salary to the market and considers each individual's experience and expertise, the value and responsibility associated with the role and internal pay equity. The Compensation Committee does not use a formula to calculate base salary increases for NEOs. In February 2018, in connection with the Business Combination, the Compensation Committee reviewed base salaries in light of the considerations noted above.

Annual Cash Bonus

The annual cash bonus rewards executives for achieving short-term financial, operational and strategic goals that drive stockholder value, as well as for individual performance during the year.

When determining target bonus opportunities for our executives, the Compensation Committee considers the range of market practices, as well as each executive's experience, relative scope of responsibility, internal pay equity considerations and any other information the Compensation Committee deems relevant in its discretion. Our targeted performance goals, established by the Compensation Committee during the first quarter of the year, are defined to focus and challenge our NEOs to perform at a high level. Payout results may be above or below target based on actual Company and individual performance.

The Compensation Committee determined the 2018 annual cash bonus payout for each NEO based on its assessment of the following:

- Quantitative Company performance goals; and
- Individual performance, including leadership and ethics, and overall value that the officer created for the Company.

The illustration below summarizes the framework the Compensation Committee uses to determine individual officer bonus payouts:

Target Bonus Opportunity	X	Company Performance Score	X	Individual Performance Factor	=	Annual Bonus Payment

Target bonus opportunity consists of base salary multiplied by bonus target, which is expressed as a percentage of base salary.The quantitative Company performance score can range between 0% and 200%, with 100% being the target.Individual performance factors can range between 0 and 1.5.

2018 Quantitative Performance Metrics

During the first quarter of 2018, the Compensation Committee established quantitative performance goals for the bonus program by taking into consideration key safety, financial and operational performance measures that are important indicators of success in our industry.Each of these metrics was based on fiscal year 2018 performance and this included periods prior to the Business Combination.

The following table shows the targets and weightings established by the Compensation Committee and the performance achieved during 2018.

Upstream

The upstream quantitative performance metrics for 2018 were tied to a mix of growth, cost control and capital efficiency metrics.The higher than expected capital and operating costs experienced in 2018 coupled with lower than expected reservoir performance resulted in under-performance of the targeted upstream quantitative metrics. Only the net production growth achieved in 2018 was within the range of target metrics set.The upstream production growth achieved was done so with significantly higher than expected capital and operating costs.As a result, the Company failed to reach the target range on any of the cost or capital efficiency targets.

Performance Metric	Weight	Threshold	Target	Over-Achieve	Weighted Payout
LOE/BOE, $BOE[1]	15%	$5.33	$5.08	$4.85	0%
Production, MBOE/Day[2]	30%	27.8	32.7	38.5	22%
Drillbit F&D, $/BOE[3]	15%	$10.50	$9.50	$8.50	0%
Reserve Replacement, %[4]	10%	125%	150%	175%	0%
Upstream EBITDAX, $MM[5]	30%	$270	$317	$380	0%
				Weighted Average	22%

(1) Lease operating expense calculated based on operated horizontal production in Kingfisher CountyExcludes other counties, legacy vertical wells, activities from other operators and revenues generated from working interest partners on the owned saltwater disposal facilities.
(2) Total reported net production. Includes operated and non-operated net production and is inclusive of acquisitions and divestiture activity.
(3) Calculated as development capital spent divided by increase in proved developed producing reserves, excluding technical revisions.
(4) Proved reserve additions divided by 2018 net production.
(5) Earnings before interest, taxes, depreciation, amortization and exploration adjusted for special itemsRepresents a full year 2018.

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Midstream

The midstream quantitative performance metrics for 2018 were also tied to a mix of growth and cost control.Additionally, midstream quantitative performance metrics included capital budgeting and safety targets. While safety is a priority across the entire enterprise, given the integration of a new business segment with a significantly different operating make up than our legacy upstream operations, management chose to have the safe integration of this business as a quantitative performance metric for 2018. The Company had zero reportable incidents in Midstream in 2018, owing in part to this heightened focus on safety. Midstream cost control and capital budgeting goals were linked to an expectation that the Company would be able to rapidly add significant third-party midstream volumes over the course of 2018.Instead, the Company experienced an environment where third-party activity on existing acreage dedications was below expectations and the amount of new third-party contracting was limited. The Company was still within the target range for operating costs, despite lower than expected gas volumes in the plant, and demonstrated capital discipline as spending on growth capital moderated to be in line with the reduced trajectory of the business development efforts.

Performance Metric	Weight	Threshold	Target	Over-Achieve	Weighted Payout
Plant OPEX, $/MMBTU[1]	20%	$0.35	$0.25	$0.15	15%
Safety, TRI[2]	10%	2	1	0	20%
CAPEX Control, % Budget[3]	10%	120%	100%	80%	20%
Midstream EBITDA, $MM[4]	60%	$69	$81-$109	$125	0%
				Weighted Average	55%

(1) Calculated for the period from February 9, 2018 - December 31, 2018.
(2) Calculated using the Occupational Safety and Health Administration Recordable Incidents Rate.
(3) Calculated as capital spent as a percentage of approved capital.Excluded expansion area and produced water capital expenditures.
(4) Earnings before interest expense, income taxes, depreciation and amortization, as well as other adjustments.

Messrs. Hackett, Smith, Chappelle and McCabe and Ms. Warnica participated in both upstream and midstream bonus plans with weighting proportionate to the respective upstream and midstream EBITDA(X) targets, resulting in a 30% weighted payout.Ms. Warnica's proportionate weighting was adjusted to 50% for each of upstream and midstream to more accurately align with her 2018 job responsibilities.Messrs. Ellis and Cole participated in only the upstream bonus plan and Mr. Collins participated in only the midstream bonus plan.

The Compensation Committee evaluated our NEO's contributions during 2018 and considered each NEO's specific contribution to our Company and assigned an individual performance factor to each executive.

Below are the actual bonus payments earned for 2018 performance.

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	2018 Annual Base Salary Annualized	Bonus Target	Annual Target Bonus Opportunity[1]	Percent of Target Achieved[2]	Actual Bonus Payout
James T. Hackett	$520,000	95%	$494,000	0%	$0
Michael A. McCabe[3]	$450,000	95%	$427,500	0%	$0
Craig W. Collins[4]	$450,000	95%	$427,500	55%	$166,396
Kimberly O. Warnica	$450,000	95%	$427,500	58%	$170,918
Ronald J. Smith[5]	$270,000	65%	$175,500	7%	$13,063
Harlan H. Chappelle[6]	$830,000	125%	$1,037,500	0%	$0
Michael E. Ellis[6]	$520,000	95%	$494,000	0%	$0
Homer “Gene” Cole[6]	$450,000	95%	$427,500	0%	$0

(1) Based on annualized earnings.
(2) Based on actual earnings.
(3) Mr. McCabe retired as of March 29, 2019.
(4) Mr. Collins’ last day of employment was April 3, 2019.
(5) Mr. Smith’s last day of employment was July 19, 2019.
(6) Messrs. Chappelle, Elis and Cole resigned effective December 26, 2018.

2018 Long-Term Incentive Awards

After consultation with its independent consultant and considering competitive market data, the demand for talent, and cost considerations, the Compensation Committee awarded LTIs to Messrs. Hackett, Smith, Chappelle, Ellis, McCabe and Cole as of February 9, 2018 in connection with the Business Combination. The Compensation Committee determined to grant 30% of the target LTI value in restricted stock awards, 30% in options and 40% in performance-based restricted stock units. The Compensation Committee awarded LTIs to each of Mr. Collins and Ms. Warnica in connection with their joining the Company in April 2018 in recognition of grants that were forfeited from prior employers, as well as during the annual grant cycle.

The table below lists the target grant-date LTI value for each NEO. The Compensation Committee’s methodologies to deliver target LTI values are similar to, but can differ from, the methodologies used for accounting purposes as reflected in the Summary Compensation Table and Grants of Plan-Based Awards Table. See the Grants of Plan-Based Awards Table for additional detail about each LTI award.

	Restricted Stock Awards	Options	Performance-Based Restricted Stock Units	Total 2018 Target Value
James T. Hackett	$0	$2,500,000	$7,500,000	$10,000,000
Michael A. McCabe[1]	$1,200,000	$1,200,000	$1,600,000	$4,000,000
Craig W. Collins[2]	$1,750,000	$375,000	$375,000	$2,500,000
Kimberly O. Warnica	$600,000	$600,000	$800,000	$2,000,000
Ronald J. Smith[3]	$225,000	$225,000	$300,000	$750,000
Harlan H. Chappelle[4]	$0	$2,500,000	$7,500,000	$10,000,000
Michael E. Ellis[4]	$0	$1,500,000	$4,500,000	$6,000,000
Homer “Gene” Cole[4]	$1,200,000	$1,200,000	$1,600,000	$4,000,000

(1) Mr. McCabe retired as of March 29, 2019.
(2) Mr. Collins' last day of employment was April 3, 2019.
(3) Mr. Smith’s last day of employment was July 19, 2019.
(4) Messrs. Chappelle, Ellis and Cole resigned effective December 26, 2018.

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Restricted Stock Awards. The Compensation Committee awards restricted stock for diversification of the LTI award mix, for retention purposes and to align NEO interests with those of our stockholders. Restricted stock provides recipients with the opportunity for capital accumulation, which leads to retention and stock ownership and a more predictable LTI value than is provided by stock options and performance units.Restricted stock awards vest pro rata over a three-year period on the anniversary of the grant date.Prior to vesting, recipients have the right to vote and accumulate dividends on, to the extent paid, the restricted shares. Any accumulated dividends are subject to the same vesting schedule as the underlying share of restricted stock.

Options. Stock options provide a direct link between officer compensation and the value delivered to stockholders. The Compensation Committee believes that stock options are inherently performance-based, as option holders only realize compensation if the value of our stock increases following the grant date. Options vest pro rata over a three-year period on the anniversary of the grant date and generally expire after 7 years unless the officer separates from the Company.

Performance-Based Restricted Stock Units (RSUs). The Compensation Committee believes a significant portion of the NEO's compensation should be "at-risk" and accordingly granted 40% of the LTI value in performance-based RSUs to all NEOs other than Mr. Collins, whose LTI reflected grants forfeited from his former employer. The RSUs vest ratably over three years. The Company expected that its net production growth on upstream and system volumes growth on midstream, when coupled with a focus on maintaining a low-cost operating environment, would drive a significant increase in operating cash flows, as measured by Earnings Before Interest, Tax, Depreciation, Amortization and Exploration ("EBITDAX"). The Compensation Committee set achievement of certain EBITDAX and EBITDAX per debt-adjusted share targets for the 2018 performance period, which was from February 9, 2018 through December 31, 2018.The number of performance-based RSUs that could be earned for the 2018 performance period was established at the lesser of:

- the product of the target performance-based RSUs multiplied by the applicable percentage determined based on the Company's EBITDAX during the performance period; and
- the product of the Target Performance-Based RSUs multiplied by the applicable percentage determined based on the Company's EBITDAX per debt-adjusted share during the performance period, each as set forth under the following charts:

Level*	EBITDAX	Performance-Based RSUs (Payout %)
Threshold	$385MM	50% of Target Performance-Based RSUs
Target	$450MM	100% of Target Performance-Based RSUs
Maximum	$540MM	200% of Target Performance-Based RSUs

Level*	EBITDAX/DAS	Performance-Based RSUs (Payout %)
Threshold	$0.85	50% of Target Performance-Based RSUs
Target	$1.00	100% of Target Performance-Based RSUs
Maximum	$1.20	200% of Target Performance-Based RSUs

* The payout percentage for determining the actual number of performance-based RSUs that have become payable will be interpolated for performance between Threshold and Target, and also for performance between Target and MaximumFor the avoidance of doubt, there will be no payout, and no performance-based RSUs will vest, if the Threshold performance level set forth above is not reached for both metrics.

Ultimately, while the average commodity price in 2018 was higher than in 2017, with lower than expected growth and higher than expected costs, the Company was not able to reach its targets. Based on the Company's performance results for the period from February 9, 2018 through December 31, 2018, the NEOs did not earn any of the 2018 performance units.Accordingly, other than Messrs. Chappelle, Ellis and Cole, who had employment contracts that provided for vesting and payment at target levels upon their separation, there was no payout associated with these awards.

Other Benefits

We provide company benefits or perquisites that we believe are standard in the industry to all of our employees.These benefits consist of group health and welfare insurance offerings for employees and their qualified dependents and a 401(k) employee savings and protection plan.The costs of the health and welfare benefits were paid for entirely by the Company for all

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employees in 2018. We make matching contributions of 5% to the 401(k) contribution of each qualified participant and pay all administrative costs to maintain the plan.

We believe that an important aspect of attracting and retaining qualified individuals to serve as executive officers involves providing market termination protection benefits. We have entered into employment agreements with our NEOs pursuant to which they are entitled to certain benefits upon qualifying terminations of employment. These arrangements are discussed in further detail in "Executive Compensation—Potential Payments Upon Termination or Change in Control".

Employment Agreements

In connection with the Business Combination, the Company entered into a letter agreement with Mr. Hackett under which, if the Company terminates Mr. Hackett's employment without cause or he resigns for good reason, within the meaning of and under the letter agreement, he will be entitled to full accelerated vesting of all Company equity awards granted to him during the three years following closing of the Business Combination that are subject to time-based vesting and accelerated vesting of any such Company equity awards that are subject to performance-based vesting at the target level of performance. The Board also approved an annual base salary for Mr. Hackett of $520,000, effective on the Closing Date, and a target annual bonus amount under an annual performance bonus program for 2018 of 95% of his annual base salary.

In addition, in connection with the Business Combination, the Company entered into employment agreements with each of Messrs. Chappelle, Ellis, McCabe, Cole, and Smith. These agreements were intended to ensure the retention and focus of the management team during the early stages of the Company's growth. The employment agreements were for terms of three years (or two years for Mr. Smith). Messrs. Chappelle, Ellis and Cole were given an opportunity by the Board to resign from the Company, which was effective December 26, 2018, Mr. McCabe was given an opportunity by the Board to retire from the Company, which was effective March 29, 2019, and on July 2, 2019 the Company and Mr. Smith came to a mutual understanding with respect to Mr. Smith's separation from the Company, which was effective July 19, 2019.See "Potential Payments Upon Termination or Change in Control—Post-Termination Compensation" below for a description of certain benefits to which these executives were entitled pursuant to their employment agreements. In addition, the Company entered into employment agreements with Mr. Collins and Ms. Warnica in April 2018 when they joined the Company. On March 22, 2019, the Company and Mr. Collins came to a mutual understanding with respect to Mr. Collins' separation from the Company, which was effective on April 3, 2019.See "Potential Payments Upon Termination or Change in Control—Post-Termination Compensation" below for a description of certain benefits to which Mr. Collins was entitled pursuant to his separation agreement.

The employment agreement for Ms. Warnica entitles her to receive an annual base salary of $450,000 and to participate in an annual performance bonus program with a target bonus award determined by the Board. For 2018, Ms. Warnica's target annual bonus amounts under this program was 95% of her annual base salary. Ms. Warnica is also entitled to receive an annual physical and reimbursement of up to $5,000 per year for tax planning services. If the Company terminates Ms. Warnica's employment without cause or she resigns for good reason, within the meaning of and under the employment agreement, she will be entitled to receive (i) a prorated annual bonus for the year of termination, determined at the discretion of the Compensation Committee and based on satisfaction of performance criteria prorated for the partial performance period, (ii) full accelerated vesting of all Company equity awards that are subject to time-based vesting, accelerated vesting of any Company equity awards that are subject to performance-based vesting at the target level of performance and full accelerated vesting of any nonqualified deferred compensation account balance or benefit, (iii) a lump-sum payment equal to $24,000 for outplacement services, (iv) 18 months of her annual base salary and1.5 times the greater of her target annual bonus and the annual bonus paid to her for the prior year and (v) payment for up to 18 months of premiums for continued coverage in the Company's group health plans and, thereafter continued participation in the Company's group health plans at her cost for up to an additional 6 months. Ms. Warnica is also entitled to receive the amounts under clauses (i), (iii), (iv) and (v) of the preceding sentence if her employment terminates due to death or disability, under and within the meaning of their respective employment agreement.If Ms. Warnica's qualifying termination of employment occurs during the fifteen months following a change in control (within the meaning of the officer's employment agreement) or, only in the case of termination without cause or resignation for good reason, during the three months prior to a change in control and is demonstrated to be in connection with the change in control, then in addition to the foregoing payments and benefits, she will be entitled to an additional lump-sum payment equal to the sum of six months of her annual base salary and 0.5 times the greater of her target annual bonus and the annual bonus paid to her for the prior year. Ms. Warnica's rights to receive termination payments and benefits, other than a prorated annual bonus for the year of termination, are conditioned upon executing a general release of claims in our favor.Ms. Warnica has also agreed to refrain from competing with the Company or soliciting its customers or employees during and for a period of 12 months following his or her employment with the Company.

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The employment agreement for Ms. Warnica further entitles her, if a termination of employment occurs during the three years following the Closing Date, to payment for any excise taxes imposed under Section 4999 of the Internal Revenue Code as a result of a change in control (within the meaning of their respective employment agreements), other than the Business Combination, plus an additional amount that puts her in the same after-tax position she would have been absent the imposition of excise taxes under Section 4999 of the Internal Revenue Code.

Tax Considerations

The Compensation Committee considers the accounting and tax treatment of executive compensation in determining the amount and form of compensation that we pay our named executive officers. For instance, the Compensation Committee reviews and considers the deductibility of executive compensation under Section 162(m) of the Code, which generally disallows tax deductions to public companies for certain compensation in excess of $1 million that is paid in any one tax year to our named executive officers (other than the chief financial officer).Prior to the effectiveness of the Tax Cuts and Jobs Act of 2017 (the “Tax Act”), there was an exception to the $1 million limitation for performance-based compensation meeting certain requirements defined by the IRS. The Tax Act mandates that for tax periods beginning in 2018, the chief financial officer is no longer excluded from this limitation and performance-based compensation is no longer exempted.Transition rules under the Tax Act will allow certain payments to be deductible based on the pre-Tax Act rules if the payments are made pursuant to binding arrangements in effect as of November 2, 2017.

All equity awards to our employees, including executive officers, and to our directors will be granted and reflected in our consolidated financial statements, based upon the applicable accounting guidance, at fair market value on the grant date in accordance with FASB ASC, Topic 718, “Compensation-Stock Compensation.”

Stock Ownership Requirements and Anti-Hedging and Anti-Pledging Policies

All of our officers who are “executive officers” for purposes of Section 16 of the Exchange Act are subject to our stock ownership requirements, which are intended to reinforce the alignment of interests between our officers and stockholders. The stock ownership requirements are as follows:

- CEO - six times base salary;
- CFO and COOs - three times base salary;
- Vice Presidents - two times base salary.

Section 16 officers have five years from their respective appointment or promotion dates to achieve the designated stock ownership level.The Compensation Committee reviews each officer’s progress toward the requirements during the first quarter of each year to determine whether the market value of shares, including the value of unvested shares, satisfies our requirements.Stock options and performance units are not counted as shares owned in measuring stock ownership. Officers who do not hold the required level of stock ownership must hold the shares they receive upon vesting of restricted stock or exercise of stock options (after payment of exercise prices and after taxes) until they have met their requirement.All of our executive officers are still within the five year window for compliance with these guidelines.

In addition, to ensure that they bear the full risks of stock ownership, officers are prohibited from engaging in hedging transactions related to our stock. Officers are also prohibited from pledging or creating a security interest in any shares of our common stock they hold, including shares in excess of the applicable ownership requirement.

Clawback Policy

In March 2018, the Company adopted a clawback policy that provides that in the event of a restatement of the Company’s financial results (other than due to a change in applicable accounting rules or interpretation), the result of which is that any performance-based compensation awarded or paid during the three years preceding such restatement to an executive would have been a lower amount had it been calculated based on such restated financial statement, and such executive engaged in intentional or unlawful misconduct which materially contributed to the need for such restatement, then the Compensation Committee shall, with some exceptions, seek to recover for the benefit of the Company the excess of the awarded compensation over the adjusted compensation.

Executive Compensation

The following table summarizes the total compensation for each NEO for the years shown.

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Summary Compensation Table

Name and Principal Position	Year	Salary ($)[1]	Bonus ($)[2]	Stock Awards ($)[3]	Option Awards ($)[3]	Non-Equity Incentive Plan Compensation ($)[4]	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($)	All Other Compensation ($)[5]	Total ($)[6]
James T. Hackett Executive Chairman and Interim CEO	2018	442,000	0	1,405,660	2,722,288	0	0	0	4,569,948
Michael A. McCabe Former Vice President and Chief Financial Officer[7]	2018	399,231	0	1,424,402	1,306,698	0	0	14,350	3,144,681
Craig W. Collins Former Vice President and COO-Midstream[8]	2018	318,462	127,524	1,824,998	452,708	166,396	0	8,670	2,898,758
Kimberly O. Warnica Executive Vice President, General Counsel, Chief Compliance Officer and Secretary[9]	2018	311,539	94,740	760,000	724,686	170,918	0	9,613	2,071,496
Ronald J. Smith Former Vice President and Chief Accounting Officer[10]	2018	239,115	0	347,075	245,006	13,063	0	13,835	858,094
Harlan H. Chappelle Former President and CEO[11]	2018	724,154	0	1,405,660	2,722,288	0	0	4,840,711	9,692,813
Michael E. Ellis Former Vice President and COO-Upstream[11]	2018	460,654	0	843,396	1,633,373	0	0	2,177,557	5,114,980
Homer “Gene” Cole Former Vice President and Chief Technical Officer[11]	2018	395,962	0	1,574,402	1,306,698	0	0	1,720,936	4,997,998

(1) Represents salary paid in 2018 from closing of the Business Combination through year-end or separation of employment, as the case may be. Mr. Collins and Ms. Warnica joined the Company in April 2018.
(2) For Mr. Collins and Ms. Warnica, this column represents the one-time cash sign-on bonus amounts received upon commencement of employment.
(3) Reflects the aggregate grant date fair values calculated in accordance with FASB Accounting Standards Codification Topic 718 "Compensation-Stock Compensation" ("ASC Topic 718"). Assumptions used in the calculation of these amounts are included in the footnotes to our consolidated financial statements. The Stock Awards column also includes the grant date fair value for the first tranche of the performance-based restricted stock units granted in 2018 at target levels. These awards vest over three years at 20% during the first year, 30% during the second year and 50% during the third year. We only recognize expense for these awards when the specified performance thresholds for future periods have been established. Only the performance goals and objectives for 2018 were established as of December 31, 2018. No amounts will be recognized for the 2019 and 2020 performance period until the specific targets have been established and probability of attainment can be measured. The value ultimately realized upon the actual vesting of the awards may or may not be equal to this determined value, as these awards are subject to performance criteria and have been valued based on assessment of that criteria as of the grant date. See the “-Grants of Plan-Based Awards Table” and “Compensation Discussion and Analysis - 2018 Long-Term Incentive Awards-Performance-Based Restricted Stock Units” for further detail on our performance unit program. It was determined in January 2019 that the first tranche of 2018 performance-based units would pay out at zero percent. If the highest level of performance conditions had been achieved for the year ending December 31, 2018, the maximum grant date fair value for the first tranche of the performance-based restricted stock units for each executive would have been as follows:

Name	Maximum Grant Date Fair Value ($)
James T. Hackett	2,811,322
Michael A. McCabe	599,749
Craig W. Collins	150,000

Kimberly O. Warnica	320,001
Ronald J. Smith	112,454
Harlan H. Chappelle	2,811,322
Michael E. Ellis	1,686,792
Homer "Gene" Cole	599,749

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(4) This column reflects annual cash bonus payments, determined by the Compensation Committee and paid in the first quarter of the following year pursuant to the Company's Annual Incentive Compensation Plan.Those awards are discussed in further detail under "Compensation Discussion and Analysis—Annual Cash Bonus."
(5) The following table describes each component of the All Other Compensation column for 2018 in the Summary Compensation Table.

Name	Year	Company Physicals ($)[(a)]	Tax & Financial Planning ($)[(b)]	Miscellaneous ($)[(c)]	Company Contributions to Defined Contribution Plan ($)[(d)]	Total All Other Compensation ($)
James T. Hackett	2018	0	0	0	0	0
Michael A. McCabe	2018	0	0	600	13,750	14,350
Craig W. Collins	2018	0	5,000	450	3,220	8,670
Kimberly O. Warnica	2018	0	5,000	300	4,313	9,613
Ronald J. Smith	2018	0	0	550	13,285	13,835
Harlan H. Chappelle	2018	0	0	4,828,284[(e)]	12,427	4,840,711
Michael E. Ellis	2018	0	5,000	2,158,807[(f)]	13,750	2,177,557
Homer "Gene" Cole	2018	0	3,505	1,703,681[(g)]	13,750	1,720,936

(a) Executives are entitled to reimbursement for the full cost of an annual physical examination through their employment agreements.
(b) Executives are entitled to up to $5,000 in reimbursement for the cost of tax preparation and planning by a certified financial planner or certified public accountant.
(c) Includes personal use of club memberships, personal use of company vehicle and health club dues, with such health club dues being capped at $600 per year.
(d) Reflects amounts contributed by us under the 401(k) employee savings and protection plan.
(e) This amount includes (i) $31,271 for personal use of club memberships; (ii) $1,022,013, which reflects the in-the-money value of the stock options (currently $0) and the actual pre-tax income realized for performance units for which vesting was accelerated upon Mr. Chappelle's resignation, valued as of the date an effective release was obtained, which was January 3, 2019, at a stock price of $1.30; the grant date fair value of which is reported in the Stock Awards and Option Awards columns of the Summary Compensation Table, as applicable; and (iii) $3,775,000, which represents the value of the benefits to which Mr. Chappelle was entitled to pursuant to his employment agreement. Please read "-Potential Payments Upon Termination or Change in Control" for additional information.
(f) This amount includes (i) $600 for health club dues; (ii) $613,207, which reflects the in-the-money value of the stock options (currently $0)and the actual pre-tax income realized for performance units for which vesting was accelerated upon Mr. Ellis' resignation, valued as of the date an effective release was obtained, which was January 3, 2019, at a stock price of $1.30; the grant date fair value of which is reported in the Stock Awards and Option Awards columns of the Summary Compensation Table, as applicable; and (iii) $1,545,000, which represents the value of the benefits to which Mr. Ellis was entitled to pursuant to his employment agreement. Please read "—Potential Payments Upon Termination or Change in Control" for additional information.
(g) This amount includes (i) $1000 for personal use of club memberships; (ii) $362,431, which reflects the in-the-money value of the stock options (currently $0) and the actual pre-tax income realized for performance units and restricted stock for which vesting was accelerated upon Mr. Cole's resignation, with the restricted stock valued as of the date of Mr. Cole's separation, which was December 26, 2018, at a stock price of $.90 and the performance units valued as of the date an effective release was obtained, which was January 3, 2019, at a stock price of $1.30; the grant date fair value of which is reported in the Stock Awards and Option Awards columns of the Summary Compensation Table, as applicable; and (iii) $1,340,250, which represents the value of the benefits to which Mr. Cole was entitled to pursuant to his employment agreement. Please read "—Potential Payments Upon Termination or Change in Control" for additional information.

(6) The amounts reflected here for Mr. Hackett and Ms. Warnica are the same as what was disclosed in the Alta Mesa Holdings, LP 10-K for the year ending December 31, 2018.
(7) Mr. McCabe retired as of March 29, 2019.
(8) Mr. Collin's last day of employment was April 3, 2019.
(9) Effective June 18, 2019, Ms. Warnica's title changed from Vice President, General Counsel, Chief Compliance Officer and Secretary to Executive Vice President, General Counsel, Chief Compliance Officer and Secretary.
(10) Mr. Smith's last day of employment was July 19, 2019.
(11) Messrs. Chappelle, Ellis and Cole resigned effective December 26, 2018.

Grants of Plan-Based Awards in 2018

The following table provides information about all plan-based long-term incentive awards, including restricted stock, stock options and performance units, granted to each NEO during 2018. The awards listed in the table were granted under the 2018 Long Term Incentive Plan and are described in more detail in "Compensation Discussion and Analysis."

Non-Equity Incentive Plan Awards. Values disclosed reflect the estimated cash payouts under the Company's annual incentive compensation plan, based on actual salaries earned in 2018. If threshold levels of performance are not met, the payout can be zero. If maximum levels of performance are achieved, the payout can be 300% of each NEO's target. The amounts actually paid to the NEOs for 2018 are disclosed in the Summary Compensation Table in the "Non-Equity Incentive Plan Compensation" column.

Equity Incentive Plan Awards. Awards reported reflect performance units, which are denominated as an equivalent of one share of Company common stock and, if earned, are paid in stock or cash at the Compensation Committee's election. Executive officers may earn from 0% to 200% of the targeted award based on the Company's EBITDAX and EBITDAX per debt-adjusted share. The threshold value reported represents the lowest earned amount, other than zero, based on a defined payout scale.

Stock Awards. Awards reported reflect restricted stock awards that vest pro-rata annually over three years, beginning with the first anniversary of the grant date, except for awards granted on August 20, 2018 to Messrs. Smith and Cole, which vest on the one year anniversary of the grant date. Dividend equivalents, if any, are accrued and paid upon the applicable vesting of the underlying award. The Company did not pay any dividends in 2018.

Option Awards. Stock options vest pro-rata annually over three years, beginning with the first anniversary of the date of grant and have a term of seven years. The exercise price is not less than the market price on the date of grant and repricing of stock options to a lower exercise price is prohibited, unless approved by stockholders.

			Estimated Future Payouts Under Non-Equity Incentive Plan Awards			Estimated Future Payouts Under Equity Incentive Plan Awards[1]						
Name	**Type of Award**	**Grant Date[2]**	**Threshold ($)**	**Target ($)**	**Max ($)**	**Threshold (#)**	**Target (#)**	**Max (#)**	**All Other Stock Awards; Number of Shares of Stock or Units (#)**	**All Other Option Awards; Number of Securities Underlying Options (#)**	**Exercise or Base Price of Option Awards ($)**	**Grant Date Fair Value of Stock and Option Awards ($)[1,3]**
James T. Hackett	Annual Cash Bonus		247,000	494,000	1,482,000							0
	Options	2/9/18								589,623	9.54	2,722,288
	Performance Units	2/9/18				393,082	786,164	1,572,328				1,405,660
Michael A. McCabe	Annual Cash Bonus		213,750	427,500	1,282,500							0
	Restricted Stock	2/9/18							125,786			1,124,528
	Options	2/9/18								283,019	9.54	1,306,698
	Performance Units	2/9/18				83,858	167,715	335,430				299,874
Craig W. Collins	Annual Cash Bonus		213,750	427,500	1,282,500							0
	Restricted Stock	4/3/18							247,875			1,749,998
	Options	4/3/18								119,511	7.06	452,708
	Performance											

	Units	4/3/18				26,558	53,116	106,232				75,000

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Kimberly O. Warnica	Annual Cash Bonus		213,750	427,500	1,282,500							0
	Restricted Stock	4/9/18							85,592			600,000
	Options	4/9/18								192,582	7.01	724,686
	Performance Units	4/9/18				57,061	114,123	228,246				160,000
Ronald J. Smith	Annual Cash Bonus		87,750	175,500	526,500							0
	Restricted Stock	2/9/18							23,585			210,849
		8/20/18							18,476			80,000
	Options	2/9/18								53,066	9.54	245,006
	Performance Units	2/9/18				15,724	31,447	62,894				56,226
Harlan H. Chappelle	Annual Cash Bonus		518,750	1,037,500	3,112,500							0
	Options	2/9/18								589,623	9.54	2,722,288
	Performance Units	2/9/18				393,082	786,164	1,572,328				1,405,660
Michael E. Ellis	Annual Cash Bonus		247,000	494,000	1,482,000							0
	Options	2/9/18								353,774	9.54	1,633,373
	Performance Units	2/9/18				235,849	471,698	943,396				843,396
Homer "Gene" Cole	Annual Cash Bonus		213,750	427,500	1,282,500							0
	Restricted Stock	2/9/18							125,786			1,124,528
		8/20/18							34,642			150,000
	Options	2/9/18								283,019	9.54	1,306,698
	Performance Units	2/9/18				83,858	167,715	335,430				299,874

(1) Performance-based restricted stock units granted in 2018 vest over three years at 20% during the first year, 30% during the second year and 50% during the third year. We only recognize expense for these awards when the specified performance thresholds for future periods have been establishedOnly the performance goals and objectives for 2018 were established as of December 31, 2018.No amounts will be recognized for the 2019 and 2020 performance period until the specific targets have been established and probability of attainment can be measured.The value ultimately realized upon the actual vesting of the awards may or may not be equal to this determined value, as these awards are subject to performance criteria and have been valued based on assessment of that criteria as of the grant date.

(2) Awards were established based on the fair market value of a Class A share of AMR on the grant date in the table and, in the case of restricted stock and restricted stock units granted on February 9, 2018, were issued upon filing of an effective registration statement, which was April 12, 2018.

(3) Reflects the aggregate grant date fair values calculated in accordance with ASC Topic 718.Assumptions used in the calculation of these amounts are included in the footnotes to our consolidated financial statements.

Outstanding Equity Awards at 2018 Fiscal Year-End

The following table reflects outstanding stock option awards and unvested and unearned stock awards (both time-based and performance-contingent) as of December 31, 2018, assuming a market value of $1.00 per share (the closing stock price of the Company's common stock on December 31, 2018).

						Stock Awards			
		Option Awards				Restricted Stock/Units[3]		Equity Incentive Plan Awards / Performance Units[4]	
		Number of Securities Underlying Unexercised Options							
Name	Grant Date[1]	Exercisable (#)	Unexercisable[2] (#)	Option Exercise Price ($)	Option Expiration Date	Number of Share or Units of Stock that Have Not Vested (#)	Market Value of Shares or Units of Stock that Have Not Vested ($)	Number of Unearned Shares, Units or Other Rights that Have Not Vested (#)	Market or Payout Value of Unearned Shares, Units or Other Rights that Have Not Vested ($)
James T. Hackett	2/9/18	0	589,623	9.54	2/8/25			786,164	786,164
Michael A. McCabe	2/9/18	0	283,019	9.54	2/8/25	125,786	125,786	134,172	134,172
Craig W. Collins	4/3/18	0	119,511	7.06	4/2/25	247,875	247,875	53,116	53,116
Kimberly O. Warnica	4/9/18	0	192,582	7.01	4/8/25	85,592	85,592	114,123	114,123
Ronald J. Smith	2/9/18 2/9/18 8/20/18	0	53,066	9.54	2/8/25	23,585 18,476	23,585 18,476	31,447	31,447
Harlan H. Chappelle[5]	2/9/18	589,623	0	9.54	12/26/21				
Michael E. Ellis[5]	2/9/18	353,774	0	9.54	12/26/21				
Homer "Gene" Cole[5]	2/9/18	283,019	0	9.54	12/26/21				

(1) Awards were established based on the fair market value of of a Class A share of AMR on the grant date in the table and, in the case of restricted stock and restricted stock units granted on February 9, 2018, were issued upon filing of an effective registration statement, which was April 12, 2018.
(2) All stock options listed vest in one-third increments on each anniversary of the grant date.
(3) Reflects the number of shares of unvested restricted stock held by our NEOs on December 31, 2018.The restricted stock will vest pro rata annually over three years, beginning with the first anniversary of the Business Combination date, except for the restricted stock granted to Mr. Smith on August 20, 2018, which will vest in full on the one year anniversary of the grant date.
(4) The number of outstanding units and estimated payout disclosed for each award assumes target payout for each tranche of the award.However, in January 2019, it was determined that the first tranche of 2018 performance-based units would pay out at zero percent.
(5) Messrs. Chappelle, Ellis and Cole resigned from the Company effective December 26, 2018.In accordance with their respective employment and separation agreements, all outstanding options, shares of restricted stock and performance units vested.Performance units were paid out at target per the agreements.The release of these awards was subject to an effective release which was received from each in January of 2019.

Option Exercise and Stock Vested in 2018

The following table provides information about the aggregate dollar value realized during 2018 by the NEOs, including option exercises, vesting of restricted stock and performance unit payouts.

	Option Awards		Stock Awards	
Name	Number of Shares Acquired on Exercise (#)	Value Realized on Exercise ($)[1]	Number of Shares Acquired on Vesting (#)[2]	Value Realized on Vesting ($)[3]
James T. Hackett	0	0	0	0
Michael A. McCabe	0	0	0[(4)]	0
Craig W. Collins	0	0	0	0
Kimberly O. Warnica	0	0	0	0
Ronald J. Smith	0	0	0	0
Harlan H. Chappelle	0	0	786,164	1,022,013
Michael E. Ellis	0	0	471,698	613,207
Homer "Gene" Cole	0	0	328,143	362,431

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(1) Reflects the actual pre-tax income realized by NEOs upon exercise of stock options, which, is the fair market value of the shares on the exercise date less the grant price.
(2) The numbers disclosed include performance unit awards paid in shares for which restrictions lapsed during 2018.
(3) Reflects the actual pre-tax income realized by NEOs upon vesting of restricted stock or performance unitsIn the case of shares of restricted stock for Mr. Cole, this was the fair market value on his date of separation, which was December 26, 2018.In the case of performance units for Messrs. Chappelle, Ellis and Cole, this was the fair market value on the date an effective release was obtained, which was January 3, 2019.
(4) Mr. McCabe's initial tranche of 2018 performance-based units were canceled on November 29, 2018 in connection with his Separation Agreement.

Potential Payments Upon Termination or Change in Control

Our NEOs are parties to employment agreements that provide them with post-termination benefits in a variety of circumstances. The amount of compensation payable in some cases may vary depending on the nature of the termination, whether as a result of voluntary termination, involuntary not-for-cause termination, termination following a change of control and in the event of disability or death of the executive. The discussion below describes the varying amounts payable in each of these situations. It assumes, in each case, that the officer's termination was effective as of December 31, 2018, and, where applicable, uses the closing price of our common stock of $1.00 on such date.In presenting this disclosure, we describe amounts earned through December 31, 2018 and, in those cases where the actual amounts to be paid out can only be determined at the time of such executive's separation from us, we estimate the amounts that would be paid out to the executives upon their termination.

The following are general definitions that apply to the termination scenarios detailed below. These definitions have been summarized and are qualified in their entirety by the full text of the applicable plans or agreements to which our NEOs are parties.For a description of the employment agreements, read "Compensation Discussion & Analysis-Employment Agreements."

Anticipatory Termination generally means a termination of the employment within the three (3) month period ending immediately prior to the Change in Control date (in which the Change in Control is a "change in control event" within the meaning of Code Section 409A), but only if (a) the NEO's employment with the Company was (i) terminated by the Company without Cause or (ii) terminated by the NEO for Good Reason, and (b) it is reasonably demonstrated by the NEO that such termination of employment (1) was at the request of a third party who has taken steps reasonably calculated to effect such Change in Control or (2) otherwise arose in connection with or anticipation of such Change in Control.

Cause is generally defined as: (A) the NEO's final conviction by a court of competent jurisdiction of a felony involving moral turpitude, or entering the plea of *nolo contendere* to such felony by the NEO; (B) the commission by the NEO of a demonstrable act of material fraud, or a proven and material misappropriation of funds or other property, of or upon the Company or any affiliate; (C) the engagement by the NEO, without the written approval of the Company, in any material activity which directly competes with the business of the Company or any affiliate, or which would directly result in a material injury to the business or reputation of the Company or any affiliate; or (D) the breach by the NEO of any material provision of his or her employment agreement. With respect to items (C) and (D) above, in order to constitute "Cause" hereunder, the NEO must also fail to cure such breach within a reasonable time period set by the Company but in no event less than twenty (20) calendar days after NEO's receipt of such notice.

Change of Control means and includes each of the following:

(A) A transaction or series of transactions (other than an offering of common stock to the general public through a registration statement filed with the Securities and Exchange Commission or a transaction or series of transactions that meets the requirements of clauses (1) and (2) of subsection (C) below) whereby any "person" or related "group" of "persons" (as such terms are used in Sections 13(d) and 14(d)(2) of the Exchange Act) (other than the Company, any of its subsidiaries, an employee benefit plan maintained by the Company or any of its subsidiaries or a "person" that, prior to such transaction, directly or indirectly controls, is controlled by, or is under common control with, the Company) directly or indirectly acquires beneficial ownership (within the meaning of Rule 13d-3 under the Exchange Act) of securities of the Company possessing more than 50% of the total combined voting power of the Company's securities outstanding immediately after such acquisition; or

(B) During any period of two consecutive years, individuals who, at the beginning of such period, constitute the Board together with any new Director(s) (other than a Director designated by a person who shall have entered into an agreement with the Company to effect a transaction described in subsections (A) or (C)) whose election by the Board or nomination for election by the Company's stockholders was approved by a vote of at least two-thirds of the

Directors then still in office who either were Directors at the beginning of such two-year period or whose election or nomination for election was previously so approved, cease for any reason to constitute a majority thereof; or

(C) The consummation by the Company (whether directly involving the Company or indirectly involving the Company through one or more intermediaries) of (x) a merger, consolidation, reorganization, or business combination or (y) a sale or other disposition of all or substantially all of the Company's assets in any single transaction or series of related transactions, or (z) the acquisition of assets or stock of another entity, in each case other than a transaction:

(1) which results in the Company's voting securities outstanding immediately before the transaction continuing to represent (either by remaining outstanding or by being converted into voting securities of the Company or the person that, as a result of the transaction, controls, directly or indirectly, the Company or owns, directly or indirectly, all or substantially all of the Company's assets or otherwise succeeds to the business of the Company (the Company or such person, the '**Successor Entity**")) directly or indirectly, at least a majority of the combined voting power of the Successor Entity's outstanding voting securities immediately after the transaction; and

(2) after which no person or group beneficially owns voting securities representing 50% or more of the combined voting power of the Successor Entity; provided, however, that no person or group shall be treated for purposes of this clause (2) as beneficially owning 50% or more of the combined voting power of the Successor Entity solely as a result of the voting power held in the Company prior to the consummation of the transaction.

Notwithstanding the foregoing, in no event shall the following constitute a Change in Control: (i) the Business Combination or any transactions occurring in connection therewith, or (ii) any initial public offering of any subsidiary of the Company that owns all or part of the Company's Midstream Assets or any other sale or disposition of such Midstream Assets directly or indirectly by the Company in connection with such initial public offering.

The Board as in effect immediately prior to the occurrence of a Change in Control shall have full and final authority, which shall be exercised in its discretion, to determine conclusively whether a Change in Control has occurred pursuant to the above definition, the date of the occurrence of such Change in Control and any incidental matters relating thereto; provided that any exercise of such authority in conjunction with a determination regarding whether a Change in Control is a "change in control event" (as defined in Treasury Regulation Section 1.409A-3(i)(5)) shall be determined on a basis consistent with such regulation.

Good Reason means the occurrence of any of the following without the NEO's prior written consent, if not cured and corrected by the Company within 60 days after written notice thereof is provided by the NEO to the Company, provided such notice is delivered within 90 days after the occurrence of the applicable condition or event and that NEO resigns from employment with the Company within 90 days following expiration of such 60-day cure period: (a) the demotion or reduction in title or rank of NEO with the Company, or the assignment to NEO of duties that are materially inconsistent with NEO's positions, duties and responsibilities with the Company, or any removal of the NEO from, or any failure to nominate for re-election the NEO to, any of such positions (other than a change due to the NEO's Disability or as an accommodation under the American with Disabilities Act), except for any such demotion, reduction, assignment, removal or failure that occurs in connection with NEO's termination of employment for Cause, Disability or death; (b) the reduction of the NEO's annual base salary and/or target bonus opportunity, as compared to his aggregate base salary and target bonus opportunity as effective immediately prior to such reduction, if such reduction of base salary and/or target bonus opportunity, on an aggregated basis, is five percent (5%) or greater of the aggregate base salary and target bonus opportunity as effective immediately prior to such reduction; (c) a relocation of the NEO's principal work location to a location in excess of 50 miles from its then current location; or (d) failure to nominate the NEO to be re-elected to the Board. For the avoidance of doubt, the closing of the Business Combination will not by itself be deemed to provide a basis for the NEO to resign for Good Reason.

Disability generally means that (a) the NEO is unable to engage in any substantial gainful activity by reason of any medically determinable physical or mental impairment which can be expected to result in death or last for a continuous period of not less than 12 months, or (b) by reason of any medically determinable physical or mental impairment which can be expected to result in death or to last for a continuous period of not less than 12 months, the NEO is receiving income replacement for a period of not less than three months under an accident and health plan covering employees of the Company. Evidence of such Disability shall be certified by a physician acceptable to both the Company and the NEO.In the event that the parties are not able to agree on the choice of a physician, each shall select one physician who, in turn, shall select a third physician to render such certification. All reasonable costs directly relating to the determination of whether the NEO has incurred a Disability for purposes of this Agreement shall be paid by the Company. The NEO agrees to submit to any examinations that are reasonably required by the attending physician or other healthcare service providers to determine whether the NEO has a Disability.

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Involuntary for Cause or Voluntary Termination without Good Reason.

No payment will be paid to the NEO.

Involuntary Termination without Cause or Termination for Good Reason.

	Mr. Hackett ($)	Mr. McCabe($)	Mr. Collins($)	Ms. Warnica($)	Mr. Smith($)
Cash Severance(1)	0	1,457,459	1,340,250	1,340,250	465,500
Pro Rata AICP Bonus(2)	0	0	166,396	170,918	13,063
Accelerated Equity Compensation(3)	786,164	259,958	300,991	199,715	73,508
Health and Welfare Benefits(4)	0	13,699	43,819	43,819	43,819
Total	786,164	1,731,116	1,851,456	1,754,702	595,890

(1) Value assumes 1.5 times salary in effect at December 31, 2018 and 1.5 times target bonus for Messrs. Collins and McCabe and Ms. Warnica and 1 times salary and target bonus for Mr. Smith. Also includes $24,000 for outplacement services for Messrs. Collins and McCabe and Ms. Warnica and $20,000 for Mr. Smith. Includes additional $117,209 lump sum payment for Mr. McCabe pursuant to his Separation AgreementSee "-Post-Termination Compensation" below.
(2) All values in the table are based on base salary earnings for the year and reflect the actual bonuses awarded under the Company's 2018 AICP.
(3) Reflects the in-the-money value of unvested stock options (currently $0), the value of unvested performance units and the value of unvested restricted stock, all as of December 31, 2018.
(4) Reflects value of 18 months of coverage under the Company's group health plans assuming continued election of the officer's current level of coverage for the full 18 months at the current rates, except for Mr. Hackett who is not entitled to continued coverage.

Death or Disability

	Mr. Hackett ($)	Mr. McCabe($)	Mr. Collins($)	Ms. Warnica($)	Mr. Smith($)
Cash Severance(1)	0	1,457,459	1,340,250	1,340,250	465,500
Pro Rata AICP Bonus(2)	0	0	166,396	170,918	13,063
Health and Welfare Benefits(3)	0	13,699	43,819	43,819	43,819
Total	0	1,471,158	1,550,465	1,554,987	522,382

(1) Value assumes 1.5 times salary in effect at December 31, 2018 and 1.5 times target bonus for Messrs. Collins and McCabe and Ms. Warnica and 1 times salary and target bonus for Mr. Smith. Also includes $24,000 for outplacement services for Messrs. Collins and McCabe and Ms. Warnica and $20,000 for Mr. Smith. Includes additional $117,209 lump sum payment for Mr. McCabe pursuant to his Separation AgreementSee "-Post-Termination Compensation" below.
(2) All values in the table are based on base salary earnings for the year and reflect the actual bonuses awarded under the Company's 2018 AICP.
(3) Reflects value of 18 months of coverage under the Company's group health plans assuming continued election of the officer's current level of coverage for the full 18 months at the current rates, except for Mr. Hackett who is not entitled to continued coverage.

Change in Control or Anticipatory Termination. In the event an NEO is terminated within 15 months after a Change in Control or an NEO incurs an Anticipatory Termination, the following payments would be due.

	Mr. Hackett ($)	Mr. McCabe($)	Mr. Collins($)	Ms. Warnica($)	Mr. Smith($)
Cash Severance(1)	0	1,896,209	1,779,000	1,779,000	688,250
Pro Rata AICP Bonus(2)	0	0	166,396	170,918	13,063
Accelerated Equity Compensation(3)	786,164	259,958	300,991	199,715	73,508
Health and Welfare Benefits(4)	0	13,699	43,819	43,819	43,819
Total	786,164	2,169,866	2,290,206	2,193,452	818,640

(1) Value assumes 2 times salary in effect at December 31, 2018 and 2 times target bonus for Messrs. Collins and McCabe and Ms. Warnica and 1.5 times salary and target bonus for Mr. Smith. Also includes $24,000 for outplacement services for Messrs. Collins and McCabe and Ms. Warnica and $20,000 for Mr. Smith. Includes additional $117,209 lump sum payment for Mr. McCabe pursuant to his Separation AgreementSee "-Post-Termination Compensation" below.
(2) All values in the table are based on base salary earnings for the year and reflect the actual bonuses awarded under the Company's 2018 AICP.
(3) Reflects the in-the-money value of unvested stock options (currently $0), the value of unvested performance units and the value of unvested restricted stock, all as of December 31, 2018.
(4) Reflects value of 18 months of coverage under the Company's group health plans assuming continued election of the officer's current level of coverage for the full 18 months at the current rates, except for Mr. Hackett who is not entitled to continued coverage.

Post-Termination Compensation

On July 2, 2019, the Company and Ronald J. Smith, Vice President and Chief Accounting Officer, came to a mutual understanding with respect to Mr. Smith's' separation from the Company, which was effective July 19, 2019. In connection with this understanding, Alta Mesa Services, LP, a wholly owned subsidiary of the Company ("Alta Mesa Services"), entered into a Separation Agreement with Mr. Smith pursuant to which he is entitled to (i) a pro-rated "target" annual bonus for 2019 in the amount of $96,164, (ii) a lump sum equal to 12 months of his base salary and 1.0 times his 2019 target annual bonus and (iii) $20,000 for outplacement services. Mr. Smith will also receive certain other benefits, such as 18 months of Company-funded continued coverage pursuant to the Consolidated Omnibus Budget Reconciliation Act of 1985, as set forth in the separation agreement. In addition, Mr. Smith retained his rights under his employment agreement to payment for any excise taxes imposed under Section 4999 of the Internal Revenue Code on their severance payments and benefits as a result of a change in control (within the meaning of his employment agreements) plus an additional amount that puts the executive in the same after-tax position he would have been absent the imposition of excise taxes under Section 4999 of the Internal Revenue Code. These payments are subject to his compliance with his non-compete, non-solicitation and other restrictive covenants, and were paid to Mr. Smith upon receipt of a general effective release of claims in the Company's favor.These amounts will be reflected in the *All Other Compensation* column of the Summary Compensation Table next year.

On March 22, 2019, the Company and Craig W. Collins, Vice President and Chief Operating Officer—Midstream, came to a mutual understanding with respect to Mr. Collins' separation from the Company, which was effective April 3, 2019.In connection with this understanding, Alta Mesa Services entered into a Separation Agreement with Mr. Collins pursuant to which he is entitled to (i) a pro-rated "target" annual bonus for 2019 in the amount of $108,925, (ii) a lump sum equal to 18 months of his base salary and 1.5 times his 2019 target annual bonus, (iii) $24,000 for outplacement services, and (iv) a 280G tax gross up payment, if applicable, in the event a change in control occurs within one year of the separation date. Mr. Collins will also receive certain other benefits, such as nine months of Company-funded continued coverage pursuant to the Consolidated Omnibus Budget Reconciliation Act of 1985, as set forth in the separation agreement. These payments are subject to his compliance with his non-compete, non-solicitation and other restrictive covenants, and were paid to Mr. Collins upon receipt of a general effective release of claims in the Company's favor. These amounts will be reflected in the *All Other Compensation* column of the Summary Compensation Table next year. In connection with his separation, Mr. Collins agreed to forfeit any right he had under all outstanding equity awards, including his rights to a 2019 equity award with a minimum market value of $1.5 million.

On December 20, 2018, each of Harlan H. Chappelle, the President and Chief Executive Officer, Michael E. Ellis, the Vice President and Chief Operating Officer—Upstream, and Homer "Gene" Cole, the Vice President and Chief Technology Officer, informed the Company that he intended to resign, effective December 26, 2018, from his position with the Company.Each of Mr. Chappelle and Mr. Ellis also informed the Company that he intended to resign as a member of the Board, effective immediately. Mr. Chappelle's and Mr. Ellis' decision to resign from the Board was not due to any disagreement with the Company relating to the operations, practices or policies of the Company.

In connection with Mr. Chappelle's, Mr. Ellis' and Mr. Cole's resignation, Alta Mesa Services entered into a separation agreement with each of them pursuant to which each individual received (a) a prorated annual bonus for the year of termination, determined based on satisfaction of performance criteria prorated for the partial performance period, which was set at $0, (b) full accelerated vesting of all Company equity awards that are subject to time-based vesting and accelerated vesting of any Company equity awards that are subject to performance-based vesting at the target level of performance, (c) a lump-sum payment equal to the sum of (i) $40,000 for Mr. Chappelle and $24,000 for each of Mr. Ellis and Mr. Cole for outplacement services, (ii) two years for Mr. Chappelle or 18 months for each of Mr. Ellis and Mr. Cole of his annual base salary and (iii) 2 times for Mr. Chappelle or 1.5 times for each of Mr. Ellis and Mr. Cole, the greater of his target annual bonus and the annual bonus paid to him for the prior year and (d) payment for up to 18 months of his premiums for continued coverage in the Company's group health plans and, thereafter, continued participation in the Company's group health plans at his cost for up to an additional 18 months for Mr. Chappelle or 6 months for each of Mr. Ellis and Mr. Cole. These amounts are reflected in the *All Other Compensation* column of the Summary Compensation Table.

In addition, Mr. Chappelle, Mr. Ellis and Mr. Cole retained their rights under their respective employment agreements to payment for any excise taxes imposed under Section 4999 of the Internal Revenue Code on their severance payments and benefits as a result of a change in control (within the meaning of their respective employment agreements) plus an additional amount that puts the executive in the same after-tax position he would have been absent the imposition of excise taxes under Section 4999 of the Internal Revenue Code.Mr. Chappelle's, Mr. Ellis' and Mr. Cole's rights to receive termination payments and benefits, other than a prorated annual bonus for the year of termination, were conditioned upon executing a general release of claims in the Company's favor, which was executed and became effective on January 3, 2019.

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On November 13, 2018, Michael A. McCabe, Vice President, Chief Financial Officer and Assistant Secretary, announced his plans to retire. Mr. McCabe retired from the Company effective March 29, 2019. In connection with his departure, the Company entered into a Separation Agreement with Mr. McCabe pursuant to which he is entitled to (i) vesting acceleration for his outstanding awards under the Company's 2018 Long-Term Incentive Plan (other than his 2018 performance units, which were canceled), (ii) 150% of his base salary in effect on the separation date, (iii) 150% of the greater of (x) his target bonus or (y) the amount of bonus paid for the year immediately preceding the year containing the separation date, (iv) $24,000 for outplacement services, and (v) a lump sum payment of approximately $117,209, in each case in exchange for certain waivers and releases for the Company's benefit. These payments were paid to Mr. McCabe upon receipt of a general effective release of claims in the Company's favor. These amounts will be reflected in the *All Other Compensation* column of the Summary Compensation Table next year.

2018 Director Compensation

Effective as of the Closing, the Company adopted a director compensation program under which each director who is not an employee of the Company or a subsidiary and is not affiliated with Riverstone, Bayou City, HPS or AM Management will receive the following cash amounts for their services on our Board:

- An annual director fee of $75,000;
- If the director serves on a committee of our Board, an additional annual fee as follows:
  - Chairperson of the Audit Committee - $22,500;
  - Audit Committee member other than the chairperson - $10,000;
  - Chairperson of the Compensation Committee - $15,000;
  - Compensation Committee member other than the chairperson - $6,000;
  - Chairperson of the Nominating and Corporate Governance Committee - $12,500; and
  - Nominating and Corporate Governance Committee member other than the chairperson - $5,000.

- If the director serves on a committee of our Board, an additional per meeting fee of $1,500 for:
  - Each member of the Audit Committee for each Audit Committee meeting attended per calendar year in excess of eight meetings;
  - Each member of the Compensation Committee for each Compensation Committee meeting attended per calendar year in excess of six meetings; and
  - Each member of the Nominating and Corporate Governance Committee for each Nominating and Corporate Governance Committee meeting attended per calendar year in excess of six meetings.

Director fees under the program are payable in arrears in four equal quarterly installments not later than the 15th day following the final day of each fiscal quarter, provided that the amount of each payment in respect of annual fees will be prorated for any portion of a quarter that a director is not serving on our Board or on a particular committee, and no fee will be payable in respect of any period prior to the Closing.

The Company also awarded 18,344 fully vested shares of Class A Common Stock to each of Ms. Walters and Messrs. Gutermuth, Tepper and Sinclair under the LTIP on April, 12, 2018, and 24,823 of Class A Common Stock to Ms. Kerrigan under the LTIP on June 18, 2018.

2018 Director Compensation Table

Name	Fees Earned or Paid in Cash ($)[1]	Stock Awards ($)[2]	All Other Compensation ($)	Total ($)
Diana J. Walters	69,621	134,462	0	204,083
Donald R. Sinclair	60,958	134,462	0	195,420
Jeffrey Tepper	66,413	134,462	0	200,875
Sylvia J. Kerrigan	24,286[3]	175,002	0	199,288
William D. Gutermuth	30,256[4]	134,462	0	164,718

(1) Represents fees earned with respect to the annual Board retainer and any applicable committee retainers.These amounts are earned quarterly and prorated for actual time served.

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(2) Reflects the aggregate grant date fair values calculated in accordance with FASB Accounting Standards Codification Topic 718 "Compensation-Stock Compensation" ("ASC Topic 718"). These amounts do not include 33,000 Class B Common Shares issued on March 23, 2017 to Ms. Walters and Messrs. Tepper and Gutermuth that were converted to Class A Common Shares on February 9, 2018.
(3) Ms. Kerrigan's service as a Director began on June 18, 2018.
(4) Mr. Gutermuth's service as a Director concluded on June 18, 2018.

2019 Director Compensation

Effective April 1, 2019, the disinterested members of the Board approved an increase in the annual director fee to $237,500 and a reduction in the stock awards under the LTIP to $0, which represents a $12,500 decrease from the prior compensation package.In addition, the disinterested members of the Board approved a cash payment of $2,000 for each Board meeting attended per calendar year in excess of seven meetings and special meeting fees of $2,000 per day to address time commitments outside of Board meetings should those be warranted.There is a cap of $25,000 per month on additional and special meeting fees. As of August 1, 2019, no special meeting fees had been paid. Ms. Walters and Messrs. Sinclair and Tepper each received $24,452, which represents the pro rata portion of their annual LTIP award to compensate for their service from February 9, 2019 through March 31, 2019.

Securities Trading Policy

Our securities trading policy provides that executive officers, including the named executive officers, and directors, may not, among other things, purchase or sell puts or calls to sell or buy our stock, engage in short sales with respect to our stock, buy our securities on margin or otherwise hedge their ownership of our stock. The purchase or sale of stock by executive officers and directors may only be made during certain windows of time and under the other conditions contained in our policy.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Security Ownership of Certain Beneficial Owners and Management

The following table sets forth information known to the Company regarding ownership of shares of voting securities of the Company, which consists of Class A Common Stock and Class C Common Stock, as of July 31, 2019 except as noted:

- each person who is known by the Company to own beneficially more than 5% of the outstanding shares of the Company’s voting securities;
- each of the Company’s current directors and each executive officer named in the Summary Compensation Table; and
- all current executive officers and directors of the Company, as a group.

Beneficial ownership is determined according to the rules of the SEC, which generally provide that a person has beneficial ownership of a security if he, she or it possesses sole or shared voting or investment power over that security or has the right to acquire such securities within 60 days, including options and warrants that are currently exercisable or exercisable within 60 days.

The beneficial ownership of voting securities of the Company is based on 383,327,227 shares of Class A Common Stock and Class C Common Stock issued and outstanding in the aggregate as of July 31, 2019.

Unless otherwise indicated, we believe that all persons named in the table below have sole voting and investment power with respect to all shares of voting securities beneficially owned by them.

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Name and Address of Beneficial Owners[1]	Number of Shares of Voting Securities[2]	Stock Acquirable Within 60 days[3]	Total Beneficial Ownership	Percent of Class %
5% or Greater Stockholders				
Investment vehicles affiliated with Riverstone Holdings(4)	85,776,000	28,466,666	114,242,666	29.8%
Orbis Investment Management Limited(5)	34,469,655	—	34,469,655	9.0%
High Mesa Holdings, LP(6)(9)	134,155,838	—	134,155,838	35.1%
HPS Investment Partners, LLC(6)(7)(9)	80,014,799	—	80,014,799	20.9%
Bayou City Energy Management LLC (6)(8)(9)	85,439,251		85,439,251	22.3%
Directors and Executive Officers				
James T. Hackett	—	196,541	196,541	—
David M. Leuschen(4)	—	—	—	—
Pierre F. Lapeyre, Jr.(4)	—	—	—	—
William W. McMullen	—	—	—	—
Don Dimitrievich	—	—	—	—
Sylvia J. Kerrigan	24,823	—	24,823	*
Jeffrey H. Tepper	51,344	—	51,344	*
Diana J. Walters	51,344		51,344	*
Donald R. Sinclair	18,344	—	18,344	*
Kimberly O. Warnica	78,644	64,194	142,838	*
Ronald J. Smith	50,991	53,066	104,057	*
Harlan H. Chappelle(6)	587,239	589,623	1,176,862	*
Michael E. Ellis(6)(8)	351,885	353,774	705,659	*
Michael A. McCabe(6)	175,064	283,019	458,083	*
Homer "Gene" Cole(6)	219,221	283,019	502,240	*
Craig W. Collins	—	—	—	*
All directors and executive officers, as a group (10 individuals)(10)	224,499	260,735	485,234	*

* Less than one percent.

(1) Unless otherwise noted, the business address of each of the following entities or individuals is c/o Alta Mesa Resources, Inc., 15021 Katy Freeway, Suite 400, Houston, Texas 77094.

(2) For Messrs. Smith, Chappelle, Ellis, McCabe, Cole and Collins, the number of shares is calculated as of their respective separation dates.

(3) Represents options exercisable within 60 days. The options are currently out of the money with a strike price between $7.01 and $9.54.In the case of Riverstone Holdings, represents warrant exercisable within 60 days at a strike price of $11.50, as may be adjusted pursuant to that certain Warrant Agreement dated as of March 23, 2017 between the Company and Continental Stock Transfer & Trust Company.

(4) Includes 16,548,894 shares of Class A Common Stock and warrants to purchase 15,133,333 shares of Class A Common Stock held of record by the Sponsor, 18,522,000 shares of Class A Common Stock and warrants to purchase 7,916,012 shares of Class A Common Stock held of record by Riverstone VI SR II Holdings, L.P. ("SR II Holdings"), 25,857,148 shares of Class A Common Stock and warrants to purchase 4,561,992 shares of Class A Common Stock held by Riverstone AMR Partners, L.P. ("AMR Partners"), 1,720,243 shares of Class A Common Stock and warrants to purchase 303,504 shares of Class A Common Stock held of record by Riverstone AMR Partners-U, LLC ("AMR Partners-U"), 3,127,715 shares of Class A Common Stock and warrants to purchase 551,825 shares of Class A Common Stock held of record by Riverstone AMR Partners-T, L.P. ("AMR Partners-T") and 20,000,000 shares of Class C Common Stock and an equal number of Common Units, each of which may be exchanged on a one-for-one basis for shares of Class A Common Stock, held of record by Riverstone VI Alta Mesa Holdings, L.P. ("Riverstone Contributor" and, together with the Sponsor, SR II Holdings, AMR Partners, AMR Partners-U and AMR Partners-T, the "Riverstone Funds"). David M. Leuschen and Pierre F. Lapeyre, Jr. are the managers of Riverstone Management Group, L.L.C. ("Riverstone Management"), which is the general partner of Riverstone/Gower Mgmt Co Holdings, L.P. ("Riverstone/Gower"), which is the sole member of Riverstone Holdings LLC ("Holdings"), which is the sole shareholder of Riverstone Energy GP VI Corp, which is the managing member of Riverstone Energy GP VI, LLC ("Riverstone Energy GP'") which is the general partner of

Riverstone Energy Partners VI, L.P., which is the general partner of AMR Partners, the manager of AMR Partners-U and the managing member of Riverstone Energy VI Holdings GP, LLC, which is the general partner of each of the Riverstone Contributor and SR II Holdings, which is the sole and managing member of Silver Run. Riverstone Energy GP is also the sole member of Riverstone Energy Partners VI (Non-U.S.), LLC, which is the general partner of AMR Partners-T, L.P. Riverstone Energy GP is managed by a managing committee consisting of Pierre F. Lapeyre, Jr., David M. Leuschen, E. Bartow Jones, N. John Lancaster, Baran Tekkora and Robert M. Tichio. As such, each of Riverstone Energy GP, Riverstone Energy GP VI Corp, Holdings, Riverstone/Gower, Riverstone Management, Mr. Leuschen and Mr. Lapeyre may be deemed to have or share beneficial ownership of the securities held directly by the Riverstone Funds. Each such entity or person disclaims any such beneficial ownership. The business address of each of these entities and individuals is c/o Riverstone Holdings LLC, 712 Fifth Avenue, 36th Floor, New York, NY 10019.

(5) Based on information contained in Schedule 13G/A filed on February 14, 2019 by Orbis Investment Management Limited ("OIML") and Orbis Investment Management (U.S.), LLC ("OIMUS"). OIML's address is Orbis House, 25 Front Street, Hamilton Bermuda HM11 and OIMUS's address is 600 Montgomery Street, Suite 3800, San Francisco, CA 94111, USA.

(6) The sole general partner of the Alta Mesa Contributor is High Mesa Holdings GP, LLC ("High Mesa GP"). High Mesa, Inc. ("High Mesa") holds a majority of the outstanding limited partner interests in the Alta Mesa Contributor and all of the outstanding limited liability company interests in High Mesa GP. The interests of the Alta Mesa Contributor are beneficially owned (either directly or through interests in High Mesa) by three groups, each consisting of affiliated parties: (i) AM MME Holdings, LP, Galveston Bay Resources Holdings, LP, Petro Acquisitions Holdings, LP, Petro Operating Company Holdings, Inc., Harlan H. Chappelle, Gene Cole, Mike McCabe, Dale Hayes, AM Equity Holdings, LP and MME Mission Hope, LLC (collectively, the "Management Holders"), (ii) HPS Investment Partners, LLC, Mezzanine Partners II Delaware Subsidiary, LLC, Offshore Mezzanine Partners Master Fund II, L.P., Institutional Mezzanine Partners II Subsidiary, L.P., AP Mezzanine Partners II, L.P., The Northwestern Mutual Life Insurance Company, The Northwestern Mutual Life Insurance Company for its Group Annuity Separate Account, Northwestern Mutual Capital Strategic Equity Fund III, LP, KCK-AMIH, Ltd. and United Insurance Company of America, Jade Real Assets Fund, L.P. (collectively, the "HPS Alta Mesa Holders") and (iii) Bayou City Energy Management, LLC, BCE-MESA Holdings, LLC, and BCE-AMH Holdings, LLC (collectively, the "Bayou City Holders"). The Class C Common Stock owned by the Alta Mesa Contributor is subject to a voting agreement pursuant to which the Alta Mesa Contributor will vote theshares of Class C Common Stock proportionately in accordance with the express direction of the HPS Alta Mesa Holders, the Bayou City Holders and the Management Holders, respectively, based upon the relative ownership in the Alta Mesa Contributor of each such group. Mr. Ellis (who is our former Chief Operating Officer - Upstream and one of our former directors), through his ownership in AM MME Holdings, LP, Galveston Bay Resources Holdings, LP, Petro Acquisitions Holdings, LP, Petro Operating Company Holdings, Inc. and AM Equity Holdings, LP, will effectively control the vote of the Management Holders, and as a result, may be deemed to beneficially own the Class C Common Stock beneficially owned by each such entity. William W. McMullen (who is one of our directors) through his ownership of the Bayou City Holders may be deemed to beneficially own the shares beneficially owned by the Bayou City Holders. Mr. Ellis, Mr. McMullen, the Management Holders, the HPS Alta Mesa Holders and the Bayou City Holders disclaim beneficial ownership of the shares of the Alta Mesa Contributor and the other Alta Mesa Contributor holders except to the extent of their respective pecuniary interests therein.

(7) Based on information contained in Schedule 13D filed on March 21, 2018, as amended on June 9, 2018, by HPS Investment Partners, LLC ("HPS"). The principal address of HPS is 40 West 57th Street, 33rd Floor, New York, New York 10019. HPS manages, directly or indirectly, each of Mezzanine Partners II Delaware Subsidiary, LLC, KFM Offshore, LLC, a wholly-owned subsidiary of Offshore Mezzanine Partners Master Fund II, L.P., KFM Institutional, LLC, a wholly-owned subsidiary of Institutional Mezzanine Partners II Subsidiary, L.P., AP Mezzanine Partners II, L.P., and Jade Real Assets Fund, L.P. (collectively, the "HPS Kingfisher Members"), and HPS, Mezzanine Partners II Delaware Subsidiary, LLC, Offshore Mezzanine Partners Master Fund II, L.P., Institutional Mezzanine Partners II Subsidiary, L.P., AP Mezzanine Partners II, L.P., The Northwestern Mutual Life Insurance Company, The Northwestern Mutual Life Insurance Company for its Group Annuity Separate Account, Northwestern Mutual Capital Strategic Equity Fund III, LP, KCK-AMIH, Ltd., United Insurance Company of America, and Jade Real Assets Fund, L.P. (collectively, the "HPS Alta Mesa Holders"). Therefore, HPS may be deemed to be the beneficial owner of all shares of the Issuer's Class A Common Stock beneficially owned by each of the HPS Kingfisher Members and the HPS Alta Mesa Holders. Included in the HPS Alta Mesa Holders' beneficial ownership, HPS manages, directly or indirectly, the HPS Alta Mesa Holders that indirectly own, through High Mesa, a certain percentage of ARM-M I, LLC, a member of the Kingfisher Contributor ("ARM-MI"), and HMS Kingfisher HoldCo, LLC, a member of the Kingfisher Contributor ("HMS"); therefore, HPS may be deemed to be the beneficial owner of such proportionate percentage of shares of the Issuer's Class A Common Stock beneficially owned by High Mesa through High Mesa's direct ownership of HMS and partial indirect ownership of ARM-MI.

(8) Based on information contained in Schedule 13D/A filed on August 22, 2018 and Form 4s filed on August 31, 2018 and September 7, 2018 by Bayou City Energy Management LLC ("BCEM"). The principal address of BCE is 1201 Louisiana

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Street, Suite 3308, Houston, Texas 77002. BCEM manages, directly or indirectly, each of BCE-AMH Holdings, LLC and BCE-MESA Holdings, LLC (the “BCE Alta Mesa Holders”) and BCE-AMR Holdings LLC (together with the BCE Alta Mesa Holders, the “BCE Holders”). Therefore, BCEM may be deemed to be the beneficial owner of all shares of the Issuer’s Class A Common Stock beneficially owned by each of the BCE Holders. The BCE Alta Mesa Holders indirectly own, through High Mesa, a certain percentage of ARM-M I, LLC, a member of the Kingfisher Contributor (“ARM-MI”), and HMS Kingfisher HoldCo, LLC, a member of the Kingfisher Contributor (“HMS”); therefore, BCEM may also be deemed to be the beneficial owner of such proportionate percentage of shares of the Issuer’s Class A Common Stock beneficially owned by High Mesa through High Mesa’s direct ownership of HMS and partial indirect ownership of ARM-MI.

(9) All or a portion of this figure reflects shares of Class C Common Stock.

(10) Excludes shares held by Messrs. Smith, Chappelle, Ellis, McCabe, Cole and Collins as they are not currently executive officers.

Securities Authorized for Issuance Under Equity Compensation Plans

The following table shows information as of December 31, 2018, with respect to shares of Class A common stock that may be issued under our existing equity compensation plans:

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders			37,017,240
Stock options	5,143,905	8.79	
Performance-based restricted stock units[1]	4,102,682	N/A	
Equity compensation plans not approved by security holders	—	—	—
Total	9,246,587		37,017,240

(1) Assumes maximum achievement of performance targets at 200% for the 2019 and 2020 performance periods.Performance-based restricted stock units have no exercise price.

Item 13. Certain Relationships and Related Transactions, and Director Independence

Certain Relationships and Related Party Transactions

Founder Shares

On November 21, 2016, Silver Run Sponsor II, LLC, our Sponsor, purchased 11,500,000 shares of Class B Common Stock, the founder shares, from us, for an aggregate purchase price of $25,000, or approximately $0.002 per share. On March 2017, we effected a stock dividend of 14,375,000 shares of Class B Common Stock, resulting in our Sponsor holding an aggregate of 25,875,000 founder shares. In March 2017, our Sponsor transferred 33,000 founder shares to each of our then independent directors (together with our Sponsor, the “initial stockholders”) at their original purchase price. On February 9, 2018, all of the outstanding founder shares were automatically converted into shares of Class A Common Stock on a one-for-one basis in connection with the Closing.

Private Placement Warrants

On March 29, 2017, our Sponsor purchased from us 15,133,333 Private Placement Warrants at a price of $1.50 per whole warrant ($22,700,000 in the aggregate) in a private placement that occurred simultaneously with the closing of our initial public offering. Each whole Private Placement Warrant is exercisable for one whole share of Class A Common Stock at a price of $11.50 per share. A portion of the purchase price of the Private Placement Warrants was placed in our trust account along with the proceeds from our initial public offering. The Private Placement Warrants are non-redeemable and exercisable on a cashless basis so long as they are held by our Sponsor or its permitted transferees.

Forward Purchase Agreement

In March 2017, we entered into the Forward Purchase Agreement pursuant to which Riverstone VI SR II Holdings, L.P. ("Fund VI Holdings") agreed to purchase an aggregate of up to 40,000,000 shares of our Class A Common Stock, plus an aggregate of up to 13,333,333 warrants ("Forward Purchase Warrant"), for an aggregate purchase price of up to $400,000,000 or $10.00 per unit (collectively, "Forward Purchase Units"). Each Forward Purchase Warrant has the same terms as each of the Private Placement Warrants.

On February 9, 2018, the Fund VI Holdings purchased 40,000,000 units pursuant to the Forward Purchase Agreement for an aggregate purchase price of $400 million.

Related Party Loans

On September 27, 2017, the Sponsor agreed to loan us an aggregate of up to $2,000,000 to cover expenses related to the Business Combination pursuant to a promissory note (the "2017 Note"). This loan was non-interest bearing and payable on the earlier of March 29, 2019 or the date on which we consummated a business combination. On September 27, 2017, we borrowed $2,000,000 under the 2017 Note. On February 9, 2018, the full $2,000,000 balance of the 2017 Note was repaid to the Sponsor.

Indemnity Agreements

Upon the closing of the Business Combination, we entered into indemnity agreements with Messrs. David M. Leuschen, Pierre F. Lapeyre, Jr., William W. McMullen, Don Dimitrievich and Donald R. Sinclair, each of whom became a director following the Business Combination, and Messrs. Harlan H. Chappelle, Michael E. Ellis, Michael A. McCabe, David Murrell, Homer "Gene" Cole and Ronald J. Smith, each of who became officers and/or directors of the Company following the Business Combination. In addition, we amended the indemnity agreements previously entered into with Messrs. Jim T. Hackett, William D. Gutermuth and Jeffrey H. Tepper and Ms. Diana J. Walters to make certain changes to reflect the Closing. We also entered into indemnity agreements with Mr. Craig W. Collins and Ms. Kimberly O. Warnica in connection with their appointment as officers of the Company. Each indemnity agreement provides that, subject to limited exceptions, and among other things, we will indemnify the director or officer to the fullest extent permitted by law for claims arising in his or her capacity as our director or officer.

Amended and Restated Limited Partnership Agreement of SRII Opco

In connection with the closing of the Business Combination, we and High Mesa Holdings, LP (the "Alta Mesa Contributor"), KFM Holdco, LLC (the "Kingfisher Contributor"), and the Riverstone Contributor (collectively, the "Contributors") entered into an amended and restated agreement limited partnership agreement (the "SRII Opco LPA") of SRII Opco, LP ("SRII Opco"). The operations of SRII Opco and the rights and obligations of the holders of SRII Opco Common Units, are set forth in the SRII Opco LPA.

Appointment as General Partner. We are the sole member of and have ownership and voting control over SRII Opco GP, LLC, a Delaware limited liability company and sole general partner of SRII Opco (the "General Partner"). The General Partner can control all the day-to-day business affairs and decision-making of SRII Opco without the approval of any other partner, unless otherwise stated in the SRII Opco LPA. As such, the General Partner, through its officers and directors, is responsible for all operational and administrative decisions of SRII Opco and the day-to-day management of SRII Opco's business.

Compensation. The General Partner is not entitled to compensation for its services as general partner. The General Partner is entitled to reimbursement by SRII Opco for any reasonable out-of-pocket expenses incurred on behalf of SRII Opco, including all our fees, expenses and costs of being a public company (including public reporting obligations, proxy statements, stockholder meetings, stock exchange fees, transfer agent fees, SEC and FINRA filing fees and offering expenses) and maintaining our corporate existence.

Distributions. The SRII Opco LPA allows for distributions to be made by SRII Opco to its partners on a pro rata basis out of "distributable cash" (as defined in the SRII Opco LPA). We expect SRII Opco may make distributions out of distributable cash periodically to the extent permitted by the debt agreements of SRII Opco and necessary to enable us to cover our operating expenses and other obligations, as well as to make dividend payments, if any, to the holders of our Class A Common Stock. In addition, the SRII Opco LPA generally requires SRII Opco to make pro rata distributions to its partners, including us, in an amount at least sufficient to allow us to pay our taxes.

SRII Opco Common Unit Redemption Right. The SRII Opco LPA provides a redemption right to the Contributors which entitles them to cause SRII Opco to redeem, from time to time, all or a portion of their SRII Opco Common Units for, at SRII Opco's option, newly issued shares of our Class A Common Stock on a one-for-one basis or a cash payment equal to the

average of the volume-weighted closing price of one share of Class A Common Stock for the five trading days prior to the date the Contributors deliver a notice of redemption for each SRII Opco Common Unit redeemed (subject to customary adjustments, including for stock splits, stock dividends and reclassifications). In the event of a “reclassification event” (as defined in the SRII Opco LPA), the General Partner is to ensure that each SRII Opco Common Unit is redeemable for the same amount and type of property, securities or cash that a share of Class A Common Stock becomes exchangeable for or converted into as a result of such “reclassification event.” Upon the exercise of the redemption right, the Contributors will surrender their SRII Opco Common Units to SRII Opco for cancellation. The SRII Opco LPA requires that we contribute cash or shares of our Class A Common Stock to SRII Opco in exchange for a number of SRII Opco Common Units in SRII Opco equal to the number of SRII Opco Common Units to be redeemed from the Contributor. SRII Opco will then distribute such cash or shares of our Class A Common Stock to such Contributor to complete the redemption. Upon the exercise of the redemption right, we may, at our option, effect a direct exchange of cash or our Class A Common Stock for such SRII Opco Common Units in lieu of such a redemption. Upon the redemption or exchange of SRII Opco Common Units held by a Contributor, a corresponding number of shares of Class C Common Stock will be cancelled.

Change of Control. In connection with the occurrence of a “general partner change of control” (as defined below), we have the right to require each partner of SRII Opco (other than us) to cause SRII Opco to redeem some or all of such partner’s SRII Opco Common Units and a corresponding number of shares of Class C Common Stock, in each case, effective immediately prior to the consummation of the general partner change of control. From and after the date of such redemption, the SRII Opco Common Units and shares of Class C Common Stock subject to such redemption will be deemed to be transferred to us and each such partner will cease to have any rights with respect to the SRII Opco Common Units and shares of Class C Common Stock subject to such redemption (other than the right to receive shares of Class A Common Stock pursuant to such redemption). A “general partner change of control” will be deemed to have occurred if or upon: (i) the consummation of a sale, lease or transfer of all or substantially all of our assets (determined on a consolidated basis) to any person or “group” (as such term is used in Section 13(d)(3)) that has been approved by our stockholders and board of directors, (ii) a merger or consolidation of the Company with any other person (other than a transaction in which our voting securities outstanding immediately prior to the transaction continue to represent at least 50.01% of our or the surviving entity’s total voting securities following the transaction) that has been approved by our stockholders and board of directors or (iii) subject to certain exceptions, the acquisition by any person or “group” (as such term is used in Section 13(d)(3)) of beneficial ownership of at least 50.01% of our voting securities, if recommended or approved by our board of directors or determined by our board of directors to be in our and our stockholders’ best interests.

Maintenance of One-to-One Ratios. The SRII Opco LPA includes provisions intended to ensure that we at all times maintain a one-to-one ratio between (a) the number of outstanding shares of Class A Common Stock and the number of SRII Opco Common Units owned by us (subject to certain exceptions for certain rights to purchase our equity securities under a “poison pill” or similar shareholder rights plan, if any, certain convertible or exchangeable securities issued under our equity compensation plans and certain equity securities issued pursuant to our equity compensation plans (other than a stock option plan) that are restricted or have not vested thereunder) and (b) the number of outstanding shares of our Class C Common Stock and the number of SRII Opco Common Units owned by the Contributors. This construct is intended to result in the Contributors having a voting interest in us that is identical to the Contributors’ economic interest in SRII Opco.

Transfer Restrictions. The SRII Opco LPA generally does not permit transfers of SRII Opco Common Units by partners, subject to limited exceptions. Any transferee of SRII Opco Common Units must assume, by operation of law or written agreement, all of the obligations of a transferring partner with respect to the transferred units, even if the transferee is not admitted as a partner of SRII Opco.

Dissolution. The SRII Opco LPA provides that the unanimous consent of all partners will be required to voluntarily dissolve SRII Opco. In addition to a voluntary dissolution, SRII Opco will be dissolved upon a change of control transaction under certain circumstances, as well as upon the entry of a decree of judicial dissolution or other circumstances in accordance with Delaware law. Upon a dissolution event, the proceeds of a liquidation will be distributed in the following order: (i) first, to pay the expenses of winding up SRII Opco; (ii) second, to pay debts and liabilities owed to creditors of SRII Opco; and (iii) third, to the partners pro-rata in accordance with their respective percentage ownership interests in SRII Opco (as determined based on the number of SRII Opco Common Units held by a partner relative to the aggregate number of all outstanding SRII Opco Common Units).

Confidentiality. Each partner has agreed to maintain the confidentiality of SRII Opco’s confidential information. This obligation excludes information independently obtained or developed by the partners, information that is in the public domain

or otherwise disclosed to a partner, in either such case not in violation of a confidentiality obligation or disclosures required by law or judicial process or approved by our chief executive officer.

Indemnification and Exculpation. The SRII Opco LPA provides for indemnification of the General Partner and the officers and managers of the General Partner and their respective subsidiaries or affiliates and provides that, except as otherwise provided therein, we, as the general partner of SRII Opco, have the same fiduciary duties to SRII Opco and its partners as are owed to a corporation organized under Delaware law and its stockholders by its directors.

Registration Rights Agreements

On March 23, 2017, we entered into a registration rights agreement (the "Sponsor Registration Rights Agreement") with our Sponsor and certain of our former and current directors, pursuant to which such parties are entitled to certain registration rights relating to (i) shares of our Class A Common Stock issued to our Sponsor and such former and current directors upon the conversion of their founder shares at the Closing and (ii) the Private Placement Warrants and warrants that may be issued upon conversion of working capital loans (and any shares of Class A Common Stock issuable upon the exercise of such warrants). In connection with the Closing, we and the Contributors entered into a Registration Rights Agreement (the "Business Combination Registration Rights Agreement" and, collectively with the Sponsor Registration Rights Agreement, the "Registration Rights Agreements"), pursuant to which we were required to register for resale shares of Class A Common Stock issuable upon the future redemption or exchange of SRII Opco Common Units by the Contributors (collectively the "Contributor Shares"). Under the Forward Purchase Agreement, we were required to, within 30 calendar days after consummation of certain transactions in connection with the Business Combination (the "Transactions"), file the registration statement registering the resale of the securities issued to Fund VI Holdings thereunder.

The holders of a majority of the Registrable Securities (as defined in the Sponsor Registration Rights Agreement) under the Sponsor Registration Rights Agreement are entitled to make up to three demands, excluding short form demands, that we register the resale of such securities. Under the Business Combination Registration Rights Agreement, we were required to, within 30 calendar days after consummation of the Transactions, file the registration statement registering the resale of the Contributor Shares. Additionally, under the Business Combination Registration Rights Agreement, the Alta Mesa Contributor is entitled to demand six underwritten offerings, the Riverstone Contributor is entitled to demand three underwritten offerings and the Kingfisher Contributor is entitled to demand two underwritten offerings, in each case if the offering is reasonably expected to result in gross proceeds of more than $50 million.

The holders under the Registration Rights Agreements also have certain "piggy-back" registration rights with respect to registration statements and rights to require us to register for resale such securities pursuant to Rule 415 under the Securities Act. However, the Sponsor Registration Rights Agreement provides that we will not permit any registration statement filed under the Securities Act with respect to the founder shares and the Private Placement Warrants and the shares of Class A Common Stock underlying such Private Placement Warrants to become effective until termination of the applicable lock-up period, which has occurred.

We agreed to bear the expenses incurred in connection with the filing of such registration statements. On February 14, 2018, we filed a Form S-1 registration statement registering the agreed upon shares, which was declared effective April 13, 2018.

Series A Certificate of Designation

Upon the closing of the Business Combination, we filed with the Secretary of State of the State of Delaware the Certificate of Designation of Series A Preferred Stock which sets forth the terms, rights, obligations and preferences of the Series A Preferred Stock that was issued to Bayou City, HPS, and AM Management, at the Closing. In connection with the resignations of Messrs. Chappelle and Ellis, AM Management and the Company entered into a letter agreement pursuant to which AM Management agreed to redeem its share of Series A-3 Preferred Stock.

Bayou City and HPS own the only outstanding shares of our Series A Preferred Stock and may not transfer the Series A Preferred Stock or any rights, powers, preferences or privileges thereunder except to an affiliate (as defined in the SRII Opco LPA). The holders of the Series A Preferred Stock are not entitled to vote on any matter on which stockholders generally are entitled to vote. In addition, the holders are not entitled to any dividends from us but will be entitled to receive, after payment or provision for debts and liabilities and prior to any distribution in respect of our Class A Common Stock or any other junior securities, liquidating distributions in an amount equal to $0.0001 per share of Series A Preferred Stock in the event of any voluntary or involuntary liquidation, dissolution or winding up of our affairs.

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The Series A Preferred Stock is not convertible into any other security of the Company, but is redeemable for the par value thereof by us upon the earlier to occur of (1) the fifth anniversary of the closing date, (2) the optional redemption of such Series A Preferred Stock at the election of the holder thereof or (3) upon a breach of the transfer restrictions described above. For so long as the Series A Preferred Stock remains outstanding, the holders of the Series A Preferred Stock are entitled to nominate and elect directors to our Board for a period of five years following the closing based on their and their affiliates' beneficial ownership of Class A Common Stock as follows:

Holder / Beneficial Ownership and Other Requirements	Designation Right
Bayou City and its affiliates	
•at least 10%	one director who must be independent for purposes of the listing rules of NASDAQ (unless the director to be nominated is William W. McMullen who need not be independent)
HPS and its affiliates	
•at least 10%	one director who must be independent for purposes of the listing rules of NASDAQ

The vote of Bayou City and HPS will be the only vote required to elect such nominees to the Board (each such director, in such capacity, a "Series A Director"). So long as the Series A Preferred Stock remains outstanding, vacancies on our Board resulting from the death, resignation, retirement, disqualification or removal of a Series A Director will be filled only by the affirmative vote of the holder of the Series A Preferred Stock. We will have the right to cause the removal of the Series A Director from our Board immediately upon redemption of the Series A Preferred Stock as described above.

Series B Certificate of Designation

Upon the closing of the Business Combination, we filed with the Secretary of State of the State of Delaware the Certificate of Designation of Series B Preferred Stock, which sets forth the terms, rights, obligations and preferences of the Series B Preferred Stock which was issued to the Riverstone Contributor at the closing.

The Riverstone Contributor owns the only outstanding share of our Series B Preferred Stock, and may not transfer the Series B Preferred Stock or any rights, powers, preferences or privileges thereunder except to an affiliate (as defined in the SRII Opco LPA). The holder of the Series B Preferred Stock is not entitled to vote on any matter on which stockholders generally are entitled to vote. In addition, the holder is not entitled to any dividends from the Company but will be entitled to receive, after payment or provision for debts and liabilities and prior to any distribution in respect of our Class A Common Stock or any other junior securities, liquidating distributions in an amount equal to $0.0001 per share of Series B Preferred Stock in the event of any voluntary or involuntary liquidation, dissolution or winding up of our affairs.

The Series B Preferred Stock is not convertible into any other security of the Company, but will be redeemable for the par value thereof by us upon the earlier to occur of (1) the fifth anniversary of the Closing Date, (2) the optional redemption of such Series B Preferred Stock at the election of the holder thereof or (3) upon a breach of the transfer restrictions described above. For so long as the Series B Preferred Stock remains outstanding, the holder of the Series B Preferred Stock will be entitled to nominate and elect directors to our Board for a period of five years following the closing based on its and its affiliates' beneficial ownership of Class A Common Stock as follows:

Holder / Beneficial Ownership and Other Requirements	Designation Right
Riverstone Contributor and its affiliates	
•at least 15%	three directors (one of whom will be the Chairman of the Board)
•less than 15% but at least 10%	two directors (one of whom will be the Chairman of the Board)
•less than 10% but at least 5%	one director (who may be the Chairman of the Board if such person is Jim Hackett)

The vote of the Riverstone Contributor will be the only vote required to elect such nominees to the Board (each such director, in such capacity, a "Series B Director"). So long as the Series B Preferred Stock remains outstanding, vacancies on our Board resulting from the death, resignation, retirement, disqualification or removal of a Series B Director will be filled only by the affirmative vote of the holder of the Series B Preferred Stock. We will have the right to cause the removal of the Series B Director from our Board immediately upon redemption of the Series B Preferred Stock as described above.

Management Services Agreement

In connection with the closing of the Business Combination, Alta Mesa entered into a management services agreement (the "Management Services Agreement") with High Mesa Holdings, LP ("High Mesa"). Under the Management Services Agreement, during the 180-day period following the closing (the "Initial Term"), Alta Mesa was to provide certain administrative, management and operational services necessary to manage the business of High Mesa and its subsidiaries (the "Services"), in each case, subject to and in accordance with an approved budget.Thereafter, the Management Services Agreement automatically renewed for additional consecutive 180-day periods (each a "Renewal Term"), unless terminated by either party upon at least 90-days written notice to the other party prior to the end of the Initial Term or any Renewal Term.As compensation for the Services, High Mesa agreed to pay us each month (i) a management fee of $10,000 and (ii) an amount equal to any and all costs and expenses incurred in connection with providing the Services.

Although the automatic renewal of this agreement occurred in the third quarter of 2018, the parties subsequently reached agreement to terminate the High Mesa Agreement effective January 31, 2019. Through April 1, 2019, Alta Mesa was obligated to take all actions that High Mesa reasonably requests to effect the transition of the Services from Alta Mesa to a successor service provider.During the transition period, High Mesa agreed to pay us (i) for all Services performed, (ii) an amount equal to our costs and expenses incurred in connection with providing the Services as provided for in the approved budget and (iii) an amount equal to our costs and expenses reimbursable pursuant to the High Mesa Agreement.Prior to 2018, we also incurred $0.8 million of costs for the direct benefit of High Mesa and the non-STACK assets, outside of the High Mesa Agreement.As of December 31, 2018, approximately $10.1 million was due from High Mesa for costs prior to 2018 and pursuant to the High Mesa Agreement.

Tax Receivable Agreement

At the closing of the Business Combination, we entered into the Tax Receivable Agreement with SRII Opco and the Alta Mesa Contributor and the Riverstone Contributor (the "TRA Holders"). This agreement generally provides for the payment by us of 85% of the amount of net cash savings, if any, in U.S. federal, state and local income tax that we actually realize (or are deemed to realize in certain circumstances) in periods after the Business Combination as a result of (i) certain tax basis increases resulting from the exchange of SRII Opco Common Units for Class A Common Stock (or, in certain circumstances, cash) pursuant to the redemption right or our right to effect a direct exchange of SRII Opco Common Units under the SRII Opco LPA, other than such tax basis increases allocable to assets held by Kingfisher or otherwise used in Kingfisher's midstream business, and (ii) interest paid or deemed to be paid by us as a result of, and additional tax basis arising from, any payments we make under the Tax Receivable Agreement. We will retain the benefit of the remaining 15% of these cash savings. The term of the Tax Receivable Agreement will continue until all such tax benefits have been utilized or have expired, unless we exercise our right to terminate the Tax Receivable Agreement or the Tax Receivable Agreement is otherwise terminated.

The actual increase in tax basis will vary depending upon the timing of the exchanges, the price of Class A Common Stock at the time of each exchange, the extent to which such exchanges are taxable transactions and the amount of the exchanging TRA Holder's tax basis in its SRII Opco Common Units at the time of the relevant exchange. The amount of such cash payments is also based on the amount and timing of taxable income we generate in the future, the U.S. federal income tax rate then applicable and the portion of our payments under the Tax Receivable Agreement that constitute interest or give rise to depreciable or amortizable tax basis. Accordingly, we are not able to estimate the actual amount of payments that would be expected under the Tax Receivable Agreement.

Additionally, if the Tax Receivable Agreement terminates early (at our election or as a result of our material breach of our obligations under the Tax Receivable Agreement, whether as a result of our failure to make any payment when due, failure to honor any other material obligation under it or by operation of law as a result of the rejection of the Tax Receivable Agreement in a case commenced under the United States Bankruptcy Code or otherwise), we are required to make a substantial, immediate lump-sum payment. This payment would equal the present value of hypothetical future payments that could be required to be paid under the Tax Receivable Agreement (calculated using a discount rate of 18%). The calculation of the hypothetical future payments will be based upon certain assumptions and deemed events set forth in the Tax Receivable Agreement, including that (i) we have sufficient taxable income to fully utilize the tax benefits covered by the Tax Receivable Agreement, (ii) all taxable

income of the Company is subject to the maximum applicable tax rates throughout the relevant period and (iii) certain loss or credit carryovers will be utilized through the expiration date of such carryovers.

Any payment upon early termination may be made significantly in advance of the actual realization, if any, of the future tax benefits to which the payment obligation relates. Except in the event of an early termination, we generally will not be obligated to make a payment under the Tax Receivable Agreement with respect to any tax benefits that we are unable to utilize.

Payments will generally be due under the Tax Receivable Agreement within 30 days following the finalization of the schedule with respect to which the payment obligation is calculated, although interest on such payments will begin to accrue from the due date (without extensions) of such tax return until such payment due date at a rate equal to LIBOR, plus 100 basis points. Except in cases where we elect to terminate the Tax Receivable Agreement early or we have available cash but fail to make payments when due, generally we may elect to defer payments due under the Tax Receivable Agreement if we do not have available cash to satisfy our payment obligations under the Tax Receivable Agreement or if our contractual obligations limit our ability to make these payments. Any such deferred payments under the Tax Receivable Agreement generally will accrue interest at a rate of LIBOR plus 500 basis points; provided, however, that interest will accrue at a rate of LIBOR plus 100 basis points if we are unable to make such payment as a result of limitations imposed by existing credit agreements.

To the extent that we are unable to make payments under the Tax Receivable Agreement for any reason, such payments will be deferred and will accrue interest until paid.

Pre-Closing Assignment Agreement

Prior to the closing of the Business Combination, Alta Mesa entered into an Assignment Agreement to transfer to its existing owners (other than the Riverstone Contributor) its remaining non-STACK oil and gas assets and all liabilities associated therewith.Such existing owners agreed to indemnify Alta Mesa for any losses relating to the non-STACK assets, including any employment, environmental and tax liabilities.

Voting Agreement

Mr. Chappelle, Mr. Ellis and certain affiliates of Bayou City and HPS own an aggregate 10% voting interest in Alta Mesa Holdings GP, LLC ("Alta Mesa GP"). These individuals and entities were a party to a voting agreement with the Alta Mesa Contributor and Alta Mesa GP, pursuant to which they have agreed to vote their interests in Alta Mesa GP as directed by the Alta Mesa Contributor. In connection with the Closing, the parties amended and restated the voting agreement to include SRII Opco as a party and the existing owners agreed to vote their interests in Alta Mesa GP as directed by SRII Opco and appoint SRII Opco as their respective proxy and attorney-in-fact with respect to any voting matters related to their respective interests in Alta Mesa GP. The voting agreement will continue in force until SRII Opco elects to terminate the agreement or, with respect to each existing owner individually, such existing owner no longer owns a voting interest in Alta Mesa GP.

Restrictive Covenant Agreement

Upon the closing of the Business Combination, we entered into a Restrictive Covenant Agreement with Asset Risk Management, LLC ("ARM"), the then current operator of Kingfisher's assets, pursuant to which ARM agreed to not conduct certain midstream services in Kingfisher, Garfield, Major, Blaine and Logan Counties, Oklahoma and certain townships in Canadian County, Oklahoma for a period ending 18 months from closing.

Transition Services Agreement

Upon the Closing, Kingfisher entered into an operating transition services agreement (the "Transition Services Agreement") with ARM. Under the Transition Services Agreement, during the six-month period following the Closing, ARM provided certain operational services with respect to certain gas gathering and processing systems and crude oil gathering facilities that were owned or acquired, by Kingfisher in Kingfisher County, Oklahoma (the "TSA Services"), in each case, subject to and in accordance with an approved budget. As compensation for the TSA Services, Kingfisher paid ARM each month (i) a management fee of $10,000, (ii) an amount equal to ARM's costs and expenses incurred in connection with providing the TSA Services as provided for in the approved budget and (iii) an amount equal to ARM's costs and expenses incurred in connection with any emergency.

Land Consulting Services

David Murrell, our Vice President of Land and Business Development, is the principal of David Murrell & Associates, which provided land consulting services to us until termination of our contract in December 2018. The primary employee of David

Murrell & Associates is his spouse, Brigid Murrell. Services were provided at a pre-negotiated hourly rate based on actual time utilized by us. Total expenditures under this arrangement were approximately $194,326, $186,000 and $146,000 for years ended December 31, 2018, 2017 and 2016, respectively. Following termination of the contract, Brigid Murrell continued to provide services to the Company as an individual contractor and was paid $8,523 for services rendered in that capacity through December 31, 2018.

Employee and Distribution

David McClure, our former Vice President of Facilities and Infrastructure, and the son-in-law of our former President and Chief Executive Officer, Harlan H. Chappelle, received total compensation of approximately $1,157,774 for the period from the closing of the Business Combination to December 31, 2018.

David Pepper, Surface Land Manager for KFM, and the cousin of our Vice President of Land and Business Development, David Murrell, received total compensation of approximately $297,134 for the period from the closing of the Business Combination to December 31, 2018.

Promissory Notes Receivables – High Mesa Services, LLC

On September 29, 2017, Alta Mesa entered into a $1.5 million promissory note receivable with its affiliate Northwest Gas Processing, LLC which obligation was subsequently transferred to High Mesa Services, LLC ("HMS"), a subsidiary of High Mesa. The promissory note bears interest, which may be paid-in-kind and added to the principal amount, at a rate of 8% per annum and matured on February 28, 2019. At December 31, 2018 and 2017, amounts due under the promissory note totaled $1.7 million and $1.5 million, respectively. HMS defaulted under the terms of the $1.5 million promissory note when the note was not paid when due on February 28, 2019, and HMS has failed to cure such default. Alta Mesa subsequently declared all amounts owing under the note immediately due and payable. Alta Mesa also has an $8.5 million promissory note receivable from HMS which matures on December 31, 2019, and bears interest at 8% per annum, which may be paid-in-kind and added to the principal amount. As of December 31, 2018 and 2017, the note receivable amounted to $11.7 million and $10.8 million, respectively. High Mesa disputes its obligations under the $1.5 million note and $8.5 million note referenced above as payable to Alta Mesa. We oppose High Mesa's claims and believe High Mesa's obligation under the notes to be valid assets of Alta Mesa and that the full amount is payable to Alta Mesa. We intend to pursue all available remedies under the promissory notes and under applicable law in connection with repayment of the promissory note by HMS. As a result of the potential conflict of interest of certain of our directors who are also controlling holders and directors of High Mesa, our non-interested directors are directing our course of action in this matter. Because High Mesa disputes its obligations under the promissory notes, we established an allowance for doubtful accounts totaling $13.4 million which is included in general and administrative expense in 2018.

Joint Development Agreement

In January 2016, our wholly owned subsidiary Oklahoma Energy entered into a Joint Development Agreement, as amended on June 10, 2016 and December 31, 2016, (the "JDA"), with BCE, a fund advised by Bayou City, to fund a portion of Alta Mesa's drilling operations and to allow Alta Mesa to accelerate development of our STACK acreage. The JDA establishes a development plan of 60 wells in three tranches, and provides opportunities for the parties to potentially agree to an additional 20 wells. Pursuant to the terms and provisions of the JDA, BCE committed to fund 100% of Alta Mesa's working interest share up to a maximum average well cost of $3.2 million in drilling and completion costs per well for any tranche. We are responsible for any drilling and completion costs exceeding approved amounts. BCE may request refunds of certain advances from time to time if funded wells previously on the drilling schedule were subsequently removed.

In exchange for carrying the drilling and completion costs, BCE receives 80% of our working interest in each wellbore, which BCE interest will be reduced to 20% of our initial working interest upon BCE achieving a 15% internal rate of return on the wells within a tranche and automatically further reduced to 12.5% of our initial interest upon BCE achieving a 25% internal rate of return on each individual tranche. Following the completion of each joint well, Alta Mesa and BCE will each bear its respective proportionate working interest share of all subsequent costs and expenses related to such joint well. Mr. William McMullen, one of our directors, is founder and managing partner of BCE. The approximate dollar value of the amount involved in this transaction, or Mr. McMullen's interests in the transaction, depends on a number of factors outside his control and is not known at this time. During the 2018 Predecessor Period, BCE advanced us approximately $39.5 million to drill wells under the JDA. As of December 31, 2018, 61 joint wells have been drilled or spudded. As of December 31, 2018 (Successor) and December 31, 2017 (Predecessor), $9.8 million and $23.4 million, respectively of revenue and net advances remaining from BCE for their working interest share of the drilling and development costs arising under the JDA were included as "Advances

from related party" in our consolidated balance sheets. At December 31, 2018, there were no funded horizontal wells in progress, and we do not expect any wells to be developed in 2019 pursuant to the JDA. On June 11, 2019, we received a letter from BCE noticing us of alleged defaults under the JDA. We dispute these allegations and intend to vigorously defend ourselves.

Related Party Policy

Prior to the closing of the Business Combination, we did not have a formal policy for the review, approval or ratification of related party transactions. Accordingly, certain of the transactions discussed above were not reviewed, approved or ratified in accordance with any such policy.

Upon closing of our Business Combination, we adopted a Related Person Transaction Policy, which addresses the reporting, review and approval or ratification of transactions with related persons. In addition, we have adopted a Corporate Code of Business Conduct and Ethics requiring us to avoid, wherever possible, all conflicts of interests, except under guidelines or resolutions approved by our Board (or the appropriate committee of our Board) or as disclosed in our public filings with the SEC. Under our Corporate Code of Business Conduct and Ethics, conflict of interest situations include any financial transaction, arrangement or relationship (including any indebtedness or guarantee of indebtedness) involving the company. A copy of our each of these policies is available on our website at www.altamesa.net.

In addition, our Audit Committee, pursuant to its charter, is responsible for reviewing and approving related party transactions to the extent that we enter into such transactions. An affirmative vote of a majority of the members of the Audit Committee present at a meeting at which a quorum is present is required in order to approve a related party transaction. A majority of the members of the entire Audit Committee will constitute a quorum. Without a meeting, the unanimous written consent of all of the members of the Audit Committee will be required to approve a related party transaction. A copy of the Audit Committee charter is available on our website. We also require each of our directors and executive officers to complete a directors' and officers' questionnaire that elicits information about related party transactions. These procedures are intended to determine whether any such related party transaction impairs the independence of a director or presents a conflict of interest on the part of a director, employee or officer. Our Audit Committee will review on an annual basis any previously approved or ratified related party transactions with our Sponsor, officers or directors, or our or their affiliates.

Board Independence

NASDAQ listing rules require that a majority of the board of directors of a company listed on NASDAQ be composed of "independent directors," which is defined generally as a person other than an officer or employee of the company or its subsidiaries or any other individual having a relationship which, in the opinion of the company's board of directors would interfere with the director's exercise of independent judgment in carrying out the responsibilities of a director. The Company's Board has determined that Mses. Diana J. Walters and Sylvia J. Kerrigan and Messrs. Donald R. Dimitrievich, Jeffrey H. Tepper, Donald R. Sinclair, David M. Leuschen and Pierre F. Lapeyre, Jr. are independent within the meaning of NASDAQ Rule 5605(a)(2).

Item 14. Principal Accountant Fees and Services

Principal Accounting Firm Fees

KPMG LLP served as the Company's independent auditor during 2018.

Aggregate fees for professional services rendered for the Company by KPMG LLP for the year ended December 31, 2018 were:

	2018
Audit fees	$ 2,966,500
Audit-related fees	359,000
Tax fees	—
All other fees	—
Total	$ 3,325,500

Audit Fees. Audit fees are primarily for the audit of the Company's consolidated financial statements included in the Form 10-K, including the audit of the effectiveness of the Company's internal control over financial reporting, and the reviews

of the Company's consolidated financial statements included in the Forms 10-Q.

Audit-Related Fees. Audit-related fees were incurred for accounting consultation regarding certain transactions that occurred during the year ended December 31, 2018.

Tax Fees. Our independent registered public accountants did not provide income tax compliance, planning and advisory services to us during the year ended December 31, 2018.

All Other Fees. KPMG LLP did not provide any "other services" as the Company's independent auditor during the year ended December 31, 2018. Alta Mesa Holdings did pay KPMG LLP $162,670 for services on a state escheatment project covering the period from January 2017 to May 2018, but that contract was cancelled prior to engaging KPMG LLP as our independent auditor.

Pre-Approval Policy

Since the Business Combination, the Audit Committee of the Board of Directors approves all services to be provided by the independent registered public accountants. All of the services provided by KPMG LLP during fiscal 2018 were approved by the Audit Committee.

PART IV

Item 15. Exhibits and Financial Statement Schedules

(a) The following documents are filed as part of this Annual Report or incorporated by reference:

1. The Consolidated Financial Statements of Alta Mesa Resources, Inc. are listed on the Index to Financial Statements in Item 8.
2. Financial Statement Schedules:
   (i) All schedules are omitted as they are not applicable, not required or the required information is included in the consolidated financial statements or notes thereto.
3. Exhibits:

2.1	Contribution Agreement, dated as of August 16, 2017, among High Mesa Holdings, LP, High Mesa Holdings GP, LLC, Alta Mesa Holdings, LP, Alta Mesa Holdings GP, LLC, the Registrant and the Contributor Owners party thereto (incorporated by reference to Exhibit 2.1 of the Registrant's Current Report on Form 8-K filed with the SEC on August 17, 2017).
2.2	Contribution Agreement, dated as of August 16, 2017, among KFM Holdco, LLC, Kingfisher Midstream, LLC, the Registrant and the Contributor Members party thereto (incorporated by reference to Exhibit 2.2 of the Registrant's Form 8-K filed with the SEC on August 17, 2017).
2.3	Contribution Agreement, dated as of August 16, 2017, between Riverstone VI Alta Mesa Holdings, L.P. and the Registrant (incorporated by reference to Exhibit 2.3 of the Registrant's Current Report on Form 8-K filed with the SEC on August 17, 2017).
3.1	Second Amended and Restated Certificate of Incorporation of Alta Mesa Resources, Inc. (incorporated by reference to Exhibit 3.1 to the Registrant's Current Report on Form 8-K filed with the SEC on February 9, 2018).
3.2	Certificate of Designations of Series A Preferred Stock of Alta Mesa Resources, Inc. (incorporated by reference to Exhibit 3.2 to the Registrant's Current Report on Form 8-K filed with the SEC on February 9, 2018).
3.3	Certificate of Designation of Series B Preferred Stock of Alta Mesa Resources, Inc. (incorporated by reference to Exhibit 3.3 to the Registrant's Current Report on Form 8-K filed with the SEC on February 9, 2018).
3.4	Bylaws of Alta Mesa Resources, Inc. (incorporated by reference to the Registrant's Registration Statement on Form S-1 filed with the SEC on (Registration No. 333-216409) filed with the SEC on March 2, 2017).
3.5	Amended and Restated Agreement of Limited Partnership of SRII Opco, LP, dated February 9, 2018 (incorporated by reference to Exhibit 10.4 to the Registrant's Current Report on Form 8-K filed with the SEC on February 9, 2018).
4.1	Specimen Class A Common Stock Certificate (incorporated by reference to Exhibit 4.2 to the Registrant's Registration Statement on Form S-1 (Registration No. 333-216409) filed with the SEC on March 2, 2017).
4.2	Specimen Warrant Certificate (incorporated by reference to Exhibit 4.3 to the Registrant's Registration Statement on Form S-1 (Registration No. 333-216409) filed with the SEC on March 2, 2017).

4.3	Warrant Agreement between the Registrant and Continental Stock Transfer & Trust Company, as warrant agent (incorporated by reference to Exhibit 4.4 of the Registrant's Current Report on Form 8-K filed with the SEC on March 29, 2017).
4.4	Registration Rights Agreement, dated March 23, 2017, among the Registrant, Silver Run Sponsor II, LLC and certain other security holders named therein (incorporated by reference to Exhibit 10.3 of the Registrant's Current Report on Form 8-K filed with the SEC on March 29, 2017).
4.5	Registration Rights Agreement, dated as of February 9, 2018, by and among Alta Mesa Resources, Inc., High Mesa Holdings, L.P., KFM Holdco, LLC and Riverstone VI Alta Mesa Holdings, L.P. (incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed with the SEC on February 9, 2018).
4.6	Amendment No. 1 to Registration Rights Agreement, dated as of February 9, 2018, by and among Alta Mesa Resources, Inc., Silver Run Sponsor II, L.L.C., and the other holders party thereto (incorporated by reference to Exhibit 4.2 to the Registrant's Current Report on Form 8-K filed with the SEC on February 9, 2018).
4.7	Indenture, dated December 8, 2016, by and among Alta Mesa Holdings, LP, Alta Mesa Finance Services Corp,. the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to Alta Mesa Holdings, LP's Current Report on Form 8-K filed with the SEC on December 8, 2016 (File No. 333-173751).
4.8*	Description of Alta Mesa Resources, Inc's Securities.
10.1	Eighth Amended and Restated Credit Agreement dated as of February 9, 2018 among Alta Mesa Holdings, LP, the lenders party hereto from time to time, and Wells Fargo Bank, National Association, as administrative agent for such Lenders (incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed with the SEC on February 9, 2018).
10.2	Master Assignment, Increase Agreement and Amendment No. 1 to Credit Agreement dated as of May 14, 2018 to the Eighth Amended and Restated Credit Agreement dated as of February 9, 2018, among Alta Mesa Holdings, LP, as borrower, Wells Fargo Bank, National Association, as administrative agent for the Lenders and as issuing lender, the Lenders listed therein and Barclays Bank PLC (incorporated by reference to Exhibit 10.1 to the Registrant's Quarterly Report on Form 10-Q filed with the SEC on November 14, 2018).
10.3	Amendment No. 2 to Credit Agreement dated as of August 13, 2018 to the Eighth Amended and Restated Credit Agreement dated as of February 9, 2018, among Alta Mesa Holdings, LP, as borrower, Wells Fargo Bank, National Association, as administrative agent for the Lenders and as issuing lender and the Lenders listed therein (incorporated by reference to Exhibit 10.2 to the Registrant's Quarterly Report on Form 10-Q filed with the SEC on November 14, 2018).
10.4*	Amendment No. 3 to Credit Agreement dated as of December 5, 2018 but effective as of February 9, 2018, to the Eighth Amended and Restated Credit Agreement dated as of February 9, 2018, among Alta Mesa Holdings, LP, as borrower, Wells Fargo Bank, National Association, as administrative agent for the Lenders and as issuing lender and the Lenders listed therein.
10.5	Amended and Restated Credit Agreement, dated May 30, 2018, by and among Kingfisher Midstream, LLC, as borrower, Wells Fargo Bank, N.A., as successor administrative agent and LC issuer, and ABN AMRO Capital USA LLC, as resigning administrative agent, the LC issuers listed therein, the Lenders listed therein and the Exiting lenders listed therein (incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed with the SEC on May 31, 2018).
10.6	Letter Agreement, dated as of February 9, 2018, by and between the Registrant and James T. Hackett (incorporated by reference to Exhibit 10.12 to the Registrant's Current Report on Form 8-K filed with the SEC on February 9, 2018).
10.7*	Letter Agreement, dated as of December 20, 2018, by and among Alta Mesa Services, LP, Randy Limbacher, John H. Campbell, Jr. and Mark P. Castiglione, and Meridian Energy LLC.
10.8*	Employment Agreement, dated as of January 7, 2019, by and between Alta Mesa Services, LP and John C. Regan.
10.9*	Employment Agreement, dated as of April 9, 2018, by and between Alta Mesa Services LP and Kimberly O. Warnica.
10.10	Employment Agreement, dated as of April 3, 2018, by and between Alta Mesa Services, LP and Craig W. Collins (incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed with the SEC on April 9, 2018).
10.11	Employment Agreement, dated as of February 9, 2018, by and between Alta Mesa Services, LP and Michael A. McCabe (incorporated by reference to Exhibit 10.15 to the Registrant's Current Report on Form 8-K filed with the SEC on February 9, 2018).
10.12	Employment Agreement, dated as of February 9, 2018, by and between Alta Mesa Services, LP and Ronald J. Smith (incorporated by reference to Exhibit 10.18 to the Registrant's Current Report on Form 8-K filed with the SEC on February 9, 2018).

10.13*	Separation Agreement, dated as of December 20, 2018, by and between Alta Mesa Services, LP and Harlan H. Chappelle
10.14*	Separation Agreement, dated as of November 13, 2018, by and between Alta Mesa Services, LP and Michael A. McCabe.
10.15*	Separation Agreement, dated as of December 20, 2018, by and between Alta Mesa Services, LP and Michael E. Ellis.
10.16*	Separation Agreement, dated as of December 20, 2018, by and between Alta Mesa Services, LP and Homer "Gene" Cole.
10.17	Alta Mesa Resources, Inc. 2018 Long Term Incentive Plan (incorporated by reference to Exhibit 10.19 to the Registrant's Current Report on Form 8-K filed with the SEC on February 9, 2018).
10.18	Form of Alta Mesa Resources, Inc. 2018 Long Term Incentive Plan Restricted Stock Award Agreement (incorporated by reference to Exhibit 10.3 to the Registrant's Quarterly Report on Form 10-Q filed with the SEC on August 15, 2018).
10.19	Form of Alta Mesa Resources, Inc. 2018 Long Term Incentive Plan Officer Stock Option Award Agreement (incorporated by reference to Exhibit 10.4 to the Registrant's Quarterly Report on Form 10-Q filed with the SEC on August 15, 2018).
10.20	Form of Alta Mesa Resources, Inc. 2018 Long Term Incentive Plan Performance-Based Restricted Stock Unit Award Agreement (incorporated by reference to Exhibit 10.5 to the Registrant's Quarterly Report on Form 10-Q filed with the SEC on August 15, 2018).
10.21	Tax Receivable Agreement, dated as of February 9, 2018, by and among the Registrant, SRII Opco, LP, Riverstone VI Alta Mesa, L.P., and High Mesa Holdings LP (incorporated by reference to Exhibit 10.5 to the Registrant's Current Report on Form 8-K filed with the SEC on February 9, 2018).
10.22	Restrictive Covenant Agreement, dated February 9, 2018, by and between the Registrant and Asset Risk Management, LLC (incorporated by reference to Exhibit 10.6 to the Registrant's Current Report on Form 8-K filed with the SEC on February 9, 2018).
10.23	Form of Indemnity Agreement (incorporated by reference to Exhibit 10.7 to the Registrant's Current Report on Form 8-K filed with the SEC on February 9, 2018).
10.24	Form of Amendment No. 1 to the Indemnity Agreement (incorporated by reference to Exhibit 10.8 to the Registrant's Current Report on Form 8-K filed with the SEC on February 9, 2018).
10.25	Management Services Agreement, dated February 9, 2018, by and between Alta Mesa Holdings, LP and High Mesa, Inc. (incorporated by reference to Exhibit 10.9 to the Registrant's Current Report on Form 8-K filed with the SEC on February 9, 2018).
10.26	Amended and Restated Voting Agreement, by and among Alta Mesa Holdings GP, LLC, BCE-AMH Holdings, LLC, BCE-MESA Holdings, LLC, Mezzanine Partners II Delaware Subsidiary, LLC, Offshore Mezzanine Partners Master Fund II, L.P., Institutional Mezzanine Partners II Subsidiary, L.P., AP Mezzanine Partners II, L.P., The Northwestern Mutual Life Insurance Company, The Northwestern Mutual Life Insurance Company For its Group Annuity Separate Account, Northwestern Mutual Capital Strategic Equity Fund III, LP, KCK-AMIH, Ltd., United Insurance Company of America, Jade Real Assets Fund, Michael E. Ellis, Harlan H. Chappelle and SRII Opco, LP, dated as of February 9, 2018 (incorporated by reference to Exhibit 10.10 to the Registrant's Current Report on Form 8-K filed with the SEC on February 9, 2018).
10.27	Alta Mesa Resources, Inc. Director Compensation Program (incorporated by reference to Exhibit 10.23 to the Registrant's Current Report on Form 8-K filed with the SEC on February 9, 2018).
10.28	Private Placement Warrants Purchase Agreement, dated March 23, 2017, between the Registrant and Silver Run Sponsor II, LLC (incorporated by reference to Exhibit 10.5 of the Registrant's Current Report on Form 8-K filed with the SEC on March 29, 2017).
10.29	Forward Purchase Agreement, dated as of March 17, 2017, between the Registrant and Riverstone VI SR II Holdings, L.P. (incorporated by reference to Exhibit 10.9 of the Registrant's Registration Statement on Form S-1/A (Registration No. 333-216409) filed with the SEC on March 17, 2017).
21.1*	Subsidiaries of the Registrant.
23.1*	Consent of KPMG, LLC
23.2*	Consent of BDO USA, LLP
23.3*	Consent of Ryder Scott Company, L. P.

31.1*	Certification of the Company's Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 7241).
31.2*	Certification of the Company's Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 7241).
32.1*	Certification of the Company's Chief Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 1350).
32.2*	Certification of the Company's Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 1350).
99.1*	Audit Letter by Ryder Scott Company, L. P. Oklahoma Properties (SEC parameters), dated April 25, 2019
101*	Interactive data files.
* filed herewith.	

Item 16. Form 10-K Summary

None.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

ALTA MESA RESOURCES, INC.

(Registrant)

By: /s/ John C. Regan

John C. Regan

Chief Financial Officer (Principal Financial Officer and Principal Accounting Officer)

Dated: August 26, 2019

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below on the 26th day of August, 2019, by the following persons on behalf of the registrant and in the capacities indicated.

	Signature	Title
By:	/s/ James T. Hackett **James T. Hackett**	Chairman of the Board, Interim Chief Executive Officer and Director (Principal Executive Officer)
By:	/s/ John C. Regan **John C. Regan**	Chief Financial Officer (Principal Financial Officer and Principal Accounting Officer)
By:	/s/ Donald R. Dimitrievich **Donald R. Dimitrievich**	Director
By:	/s/ William W. McMullen **William W. McMullen**	Director
By:	/s/ Pierre F. Lapeyre, Jr. **Pierre F. Lapeyre, Jr.**	Director
By:	/s/ Jeffrey H. Tepper **Jeffrey H. Tepper**	Director
By:	/s/ Diana J. Walters **Diana J. Walters**	Director
By:	/s/ Sylvia J. Kerrigan **Sylvia J. Kerrigan**	Director
By:	/s/ David M. Leuschen **David M. Leuschen**	Director
By:	/s/ Donald R. Sinclair **Donald R. Sinclair**	Director